BEFORE THE

PUBLIC SERVICE COMMISSION OF WISCONSIN

Application of Wisconsin Public Service Corporation for Authority to Adjust Electric and Natural Gas Rates — 6690-UR-120

FINAL DECISION

This is the Final Decision concerning the application of Wisconsin Public Service Corporation (WPSC) for authority to increase Wisconsin retail electric and natural gas rates in 2011 and to consider the over-recovery of fuel cost in docket 6690-UR-103.

Final overall rate changes are authorized consisting of a $20,997,000 annual rate increase for Wisconsin retail electric operations, a 2.21 percent increase, and an $8,275,000 annual rate decrease for Wisconsin retail natural gas operations, a 2.22 percent decrease, for the test year ending December 31, 2011, based on a 10.30 percent return on common equity. The electric rate increase, coupled with the 2010 related fuel refund in docket 6690-FR-103, provides an overall $5,758,000 annual rate increase for Wisconsin retail electric operations, a 0.61 percent increase.

Introduction

On April 1, 2010, WPSC filed a request for authority to increase its Wisconsin retail electric rates by $64,220,000, a 6.86 percent increase, and to increase its Wisconsin retail natural gas rates by $4,955,000, a 1.20 percent increase, to be effective January 1, 2011. These increases are based on an 11.25 percent return on common equity.

In addition to its request to increase Wisconsin retail rates for its 2011 filed deficiencies, WPSC requested that the Commission authorize a limited rate reopener in 2011 to adjust its retail electric and natural gas rates for 2012.

On May 26, 2010, a prehearing conference was held to determine the issues to be addressed in this docket and to establish a schedule for the hearing. On September 14, 2010, technical hearings were held in Madison. On September 21, 2010, public hearings were held in Madison, Green Bay, and Wausau.

The Commission considered this matter at its open meeting of December 16, 2010.

The parties, for purposes of review under Wis. Stat. §§ 227.47 and 227.53, are listed in Appendix A. Others who appeared are listed in the Commission's files.

Findings of Fact

1. Presently authorized rates for WPSC's Wisconsin retail electric utility operations will produce total operating revenues of $951,324,000 for the test year ending December 31, 2011, which results in an adjusted net operating income of $89,909,000 and an annual revenue deficiency of $20,997,000. Presently authorized rates for WPSC's Wisconsin retail natural gas utility operations will produce total operating revenues of $372,794,000 for the test year ending December 31, 2011, which results in an adjusted net operating income of $32,282,000 and an annual revenue excess of $8,275,000.

2. For the Wisconsin retail electric utility, the estimated rate of return on average net investment rate base of $1,294,002,000 at current rates subject to the Commission's jurisdiction for the test year is 6.95 percent, which is inadequate.

3. For the Wisconsin retail natural gas utility, the estimated rate of return on average net investment rate base of $346,671,000 at current rates subject to the Commission's jurisdiction for the test year is 9.34 percent, which is excessive.

4. A reasonable increase in operating revenue for the test year to produce a 7.86 percent return on WPSC's average net investment rate base for Wisconsin retail electric operations is $20,997,000.

5. A reasonable decrease in operating revenue for the test year to produce a 7.72 percent return on WPSC's average net investment rate base for natural gas operations is $8,275,000.

6. WPSC's filed operating income statements and net investment rate base for the test year, as adjusted for Commission decisions, are reasonable.

7. Commission staff's forecasted electric and natural gas sales are reasonable.

8. It is appropriate to offset the 2010 fuel cost over-recovery against the 2011 test year electric utility revenue deficiency.

9. It is reasonable in this proceeding to forecast fuel costs based on the New York Mercantile Exchange (NYMEX) natural gas futures prices as of November 8, 2010, and independent consultant estimates of spot coal prices as of that date.

10. A reasonable level of total company test year fuel rules monitored fuel costs is $334,100,000.

11. It is reasonable to monitor 2011 fuel costs using the following ranges: plus or minus 8 percent monthly; cumulative ranges of plus or minus 8 percent for the first month of the year, plus or minus 5 percent for the second month of the year, and plus or minus 2 percent for the remaining months of the year; and plus or minus 2 percent for the annual range.

12. It is reasonable to not require WPSC either to refund its fuel cost recoveries for 2008 and 2009 Weston 4 exfoliation-related replacement power costs or be denied recovery of these costs for 2010 or in its 2011 test year revenue requirement.

13. It is reasonable to not require WPSC to inspect either the Weston 4 high pressure and intermediate pressure steam turbines for solid particle erosion, or the superheater and reheater tubes for wall thickness, during the next major outage and provide a report to the Commission. It is also not reasonable to require WPSC to install a "rainbow" of different alloys in the superheater for the purpose of evaluating the various alloys for resistance to magnetite deposition and exfoliation.

14. It is reasonable to accept WPSC's filed Weston 4 Equivalent Forced Outage Rate (EFOR) of 12.3 percent for purposes of forecasting its 2011 test year fuel costs.

15. It is reasonable to allow WPSC to recover its attorney's fees associated with the negotiation and recovery of its rail delivery settlement.

16. It is reasonable to require WPSC to continue reporting monthly to the Commission its actual total system cost of generation and purchased energy less the revenues from opportunity sales of energy and capacity (monitored fuel costs).

17. It is reasonable that the monitored fuel costs approved in this proceeding be used as the fuel cost plan if the new fuel rule is implemented during the 2011 test year. The annual bandwidth will remain at plus or minus 2 percent on an annual basis.

18. It is reasonable for the Commission to continue to apply the current definition of monitored fuel costs to WPSC for the 2011 test year.

19. It is reasonable to use the fuel costs in Appendix D for monthly monitoring of WPSC's 2011 fuel costs pursuant to Wis. Admin. Code ch. PSC 116.

20. It is not reasonable to include incentive pay plans costs in test year electric and natural gas revenue requirements.

21. It is reasonable to include the operation and maintenance (O&M) expense impact, including payroll taxes, of the equivalent of a 1.0 percent furlough for all WPSC employees in the electric and natural gas revenue requirements.

22. It is reasonable to include the Commission staff forecasted levels of distribution maintenance expense, customer assistance expense, office supplies and expense, outside services employed expense, injuries and damages expense, and uncollectible expense in electric and natural gas revenue requirements.

23. It is reasonable to include incremental costs of $1,072,000 associated with high cost health plans in electric and natural gas revenue requirements.

24. It is reasonable to authorize recovery of deferred pre-construction costs incurred for the High Country Wind generation project in the amount of $463,000 amortized over 2011 and 2012.

25. It is not appropriate to revise the current caps on the annual revenue adjustments under the Revenue Stabilization Mechanism (RSM).

26. It is reasonable for WPSC to earn a current return on 50 percent of construction work in progress (CWIP).

27. It is reasonable that the allowance for funds used during construction (AFUDC) rate remain at the adjusted weighted cost of capital.

28. It is reasonable for WPSC to earn a current return on the unamortized balances of the De Pere Energy Center (DEC) premium and Kewaunee Nuclear Power Plant (KNPP) non-qualified decommissioning trust fund at the authorized pre-tax weighted average cost of capital.

29. It is reasonable for WPSC to earn a current return on the unamortized balances of the KNPP contingent loss deferral and RSM deferral at the authorized short-term debt rate.

30. Should the Commission choose to address the issue of appropriately aligning customer service conservation and load management activities with statewide energy efficiency programs before WPSC's next rate proceeding, WPSC should work with Commission staff to review its customer service conservation and load management activities to determine if they are still appropriate and propose any changes needed to meet the Commission's policy objectives.

31. If WPSC's customer service conservation activities are modified as a result of any Commission action regarding the appropriate use of customer service conservation and load management dollars, WPSC should propose modifications to the measures of success for these activities, consistent with Commission policy and proposed changes in activities.

32. It is appropriate for WPSC to file a final report on the WPSC/Focus on Energy Weston 4 programs. The report should include final achievement towards goals and audited expenditures. If it is determined that any of the dollars budgeted for Weston 4 programs in 2008 and 2009 were not spent, WPSC should work with Commission staff and the Statewide Energy Efficiency and Renewable Administration to remit these funds.

33. It is not reasonable to approve the load management bonus and incentive proposed by WPSC.

34. The reasonable level of expensed conservation costs recoverable in rates for the 2011 test year exclusive of additional payments to Focus on Energy related to the Second Revised Energy Efficiency Stipulation of Wisconsin Public Service Corporation and the Citizens' Utility Board (Energy Efficiency Stipulation) approved in the December 30, 2008, Final Decision in docket 6690-UR-119 is $17,963,766 for electric utility operations and $7,463,773 for natural gas utility operations. The level for electric utility operations consists of the conservation budget of $17,436,893, and an escrow adjustment of $526,873. The electric escrow adjustment represents the test year amortization of the projected overspent escrow balance at December 31, 2010, over two years. The level for natural gas operations consists of the conservation budget of $8,994,370, and an escrow adjustment of ($1,530,597). The natural gas escrow adjustment represents the test year amortization of the projected underspent escrow balance at December 31, 2010, over two years.

35. It is appropriate for WPSC's 2011 and 2012 Focus on Energy contributions to be at the levels specified in the Energy Efficiency Stipulation pilot as approved in docket 6690-UR-119.

36. The reasonable level of expenses recoverable in rates for the 2011 test year for additional payments to Focus on Energy related to the Energy Efficiency Stipulation pilot is $11,735,383 for electric utility operations and $7,276,790 for natural gas utility operations.

37. It is reasonable to continue accounting for allowable electric and natural gas conservation expenditures and additional Focus on Energy payments associated with the Energy Efficiency Stipulation on an escrow basis.

38. It is reasonable to begin recording the test year escrowed conservation amortizations, additional Focus on Energy payments, and the amortization of the 2009 Revenue Stabilization Mechanism adjustment as of the effective date of this Final Decision.

39. It is reasonable to record the full amounts of all other amortizations in the test year.

40. It is reasonable to include all uncontested Commission staff adjustments to WPSC's filed electric and natural gas income statements and average net investment rate bases.

41. A long-term range of 49 percent to 54 percent for WPSC's common equity ratio, on a financial basis, is reasonable and provides adequate financial flexibility.

42. It is reasonable for the Commission to determine what and how much debt imputation to include in the financial capital structure based on its assessment and allocation of any associated risk rather than the assessment of any rating agency.

43. No debt equivalent for off-balance sheet obligation categories of advances from affiliated companies, affiliated capital leases, purchased power capital leases, guarantees, underfunded pension and other post-retirement employee benefit plans, and asset retirement obligations, is imputed into the financial capital structure for the test year.

44. A reasonable estimate of the debt equivalent of WPSC's off-balance sheet obligations relating to its non-purchased power operating leases, to be imputed into the financial capital structure for the test year, is $4,309,000.

45. A reasonable estimate of the debt equivalent of WPSC's off-balance sheet obligations relating to its Purchased Power Agreements (PPA), to be imputed into the financial capital structure for the test year, is $107,998,000.

46. No debt equivalent for off-balance sheet obligations relating to wind, parallel generation, and renewable portfolio standard (RPS) PPAs is imputed into the financial capital structure for the test year.

47. A reasonable estimate of the debt equivalent of WPSC's off-balance sheet obligations for its wind-related land leases, to be imputed into the financial capital structure for the test year, is $42,000.

48. A reasonable estimate of subsidiary debt to be imputed into the financial capital structure for the test year is $8,282,000.

49. It is appropriate to remove WPSC's proposed 2011 long-term debt issuance from the test year to reflect the excess temporary cash investments and minimal short-term debt borrowing reflected in the proposed test year.

50. A reasonable financial capital structure for the test year consists of 50.24 percent common equity, 2.45 percent preferred stock, 38.99 percent long-term debt, 2.56 percent short-term debt, and 5.76 percent off-balance sheet obligation debt equivalents, including subsidiary debt.

51. It is reasonable to revise WPSC's dividend restrictions based on the capital structure determinations in this proceeding.

52. It is reasonable to require WPSC to submit a ten-year financial forecast in its next rate proceeding.

53. It is reasonable to require WPSC to submit in its next rate proceeding, detailed information regarding all off-balance sheet obligations for which the financial markets will calculate a debt equivalent.

54. A reasonable utility capital structure for ratemaking for the test year consists of 51.65 percent common equity, 2.69 percent preferred stock, 42.85 percent long-term debt, and 2.81 percent short-term debt.

55. A reasonable return on utility common stock equity is 10.30 percent.

56. A reasonable interest rate for short-term borrowing through commercial paper is 0.58 percent for the test year.

57. A reasonable interest rate for short-term borrowing through the master note is 0.43 percent for the test year.

58. A reasonable average embedded cost for long-term debt is 5.59 percent for the test year.

59. A reasonable average cost for preferred stock is 6.08 percent for the test year.

60. A reasonable weighted average composite cost of capital is 7.90 percent.

61. It is reasonable to continue to rely on the results of one or more electric cost-of-service studies (COSS) along with other factors, such as bill impacts, when allocating revenue responsibility.

62. It is reasonable to approve rates for electric service for the test year to achieve customer class changes in revenue as shown in Appendix B.

63. It is reasonable to direct Commission staff to work with WPSC, intervenors in this case, and other major Wisconsin investor-owned utilities to collect information on the costs associated with single-phase and three-phase primary distribution circuits.

64. It is reasonable to change language in the WPSC Response Rewards Program, create a new comprehensive lighting tariff (Ls-1), eliminate the Residential and Commercial

Space Heating and Cooling tariffs (RC-S1 and CG-S1), cancel the General Water Heating tariff (GW-X), change extension credits, and make the other minor revisions to electric customer tariffs and rules proposed by WPSC.

65. It is reasonable to order WPSC to close the two-tier residential time-of-use (TOU) tariff to new customers and to work with existing residential two-tier TOU customers on moving to the residential three-tier TOU offering or the Response Rewards program.

66. It is reasonable to direct WPSC to develop a three-tier TOU tariff for its small commercial customers for presentation at the time of its next rate proceeding.

67. It is reasonable to base the buyback rates for WPSC's parallel generation tariffs on locational marginal prices in the Midwest Independent Transmission System Operator, Inc. (Midwest ISO) market.

68. It is reasonable to approve WPSC's proposed rule changes for its net billing tariff.

69. It is reasonable for the Commission to order WPSC to increase the capacity limit of its PG-4 net metering tariff, provided that customer-owned generation is required to be sized according to the customer's annual load requirement and that excess energy supplied to WPSC is credited at the standard buyback rate.

70. It is reasonable to set the NatureWise renewable energy premium based on the full incremental cost of renewable energy for the NatureWise program, which is $2.40/100 kilowatt-hour (kWh) block.

71. The Real Time Market Pricing service schedule proposed by WPSC is reasonable.

72. It is not reasonable to increase the interruptible credit at this time.

73. It is reasonable to continue to rely on the results of one or more natural gas COSS along with other factors, such as bill impacts, as guides for revenue allocation and rate design.

74. It is reasonable to authorize rates for natural gas service as shown in Appendix C.

75. It is reasonable to modify the application of the supercompressability factor to include gas metered at pressures of two pounds per square inch or greater.

76. It is reasonable to incorporate a $1,680,000 reduction in authorized electric revenues and a $420,000 reduction in authorized natural gas revenues pursuant to the Energy Efficiency Stipulation.

77. It is reasonable to revise the electric and gas RSM tariffs in a manner consistent with the Energy Efficiency Stipulation.

78. It is reasonable to include $3,031,000 in the electric revenue requirement and $1,515,000 in the natural gas revenue requirement for amounts associated with 2005 Wisconsin Act 141 (Act 141) large-energy customer billing limitations.

79. It is reasonable to allow WPSC to file a limited 2012 rate reopener that includes the items identified by the Commission in the opinion section of this Final Decision.

Conclusions of Law

The Commission concludes it has jurisdiction under Wis. Stat. §§ 1.12, 196.02, 196.025, 196.03, 196.19, 196.20, 196.21, 196.37, 196.374, 196.395, and 196.40 and Wis. Admin. Code chs. PSC 113, 116, and 134 to enter a Final Decision authorizing WPSC to place in effect the rates and rules for electric and natural gas utility service set forth in Appendices B and C, subject to the conditions specified in this Final Decision. The rates and rules for electric and natural gas utility service in Appendices B and C are reasonable and appropriate as a matter of law.

Opinion

Applicant and Its Business

WPSC is a public utility, as defined in Wis. Stat. § 196.01(5), engaged in the production, transmission, distribution, and sale of electricity, and in the purchase, distribution, and sale of natural gas in a service area of approximately 11,000 square miles in northeastern Wisconsin and adjacent parts of upper Michigan. Cities that WPSC serves with retail electric service or natural gas service include Green Bay, Marinette, Oshkosh, Rhinelander, Sheboygan, Stevens Point, and Wausau in Wisconsin, and Menominee in Michigan. WPSC is an operating subsidiary of Integrys Energy Group, Inc. (Integrys), a holding company headquartered in Chicago, Illinois.

WPSC also sells electricity at wholesale rates to other utilities and electric cooperatives for resale. The Federal Energy Regulatory Commission (FERC) regulates these wholesale sales. WPSC's wholesale rates, therefore, are not affected by these proceedings. Similarly, the rates applicable to retail sales of electricity and natural gas to Michigan customers are not subject to the jurisdiction of this Commission and are not affected by these proceedings.

Offsetting of the 2010 Fuel Cost Over-Recoveries Against the Electric Utility Revenue Deficiency in 2011

The 2011 revenue requirement for the electric utility results in a revenue deficiency of $20,997,000 on a Wisconsin retail basis. Commission staff's estimated 2010 fuel cost over-recovery in docket 6690-FR-103, including accrued interest, totals $15,239,000. Offsetting the estimated 2010 fuel cost over-recovery against the 2011 revenue deficiency results in a net revenue deficiency of $5,758,000 on a Wisconsin retail basis. Any actual remaining fuel cost over-recoveries will be known when total 2010 fuel costs are calculated.

In testimony, Commission staff suggested that the Commission consider applying any 2010 fuel cost refund or credit to the 2011 revenue deficiency in order to minimize a 2011 rate increase rather than ordering a rate decrease that would be quickly followed by a rate increase. In rebuttal testimony, WPSC agreed that applying the 2010 fuel cost refund or credit to the 2011 revenue deficiency would help provide more rate stability rather than ordering a rate decrease that would be quickly followed by a rate increase. Because the final amount of the 2010 fuel refund will not be known until after the 2011 rates are expected to be approved, WPSC proposed to refund the actual amount subject to refund at the time of discussion of record in this proceeding, and to refund any additional amount on a one-time basis in 2011. WPSC proposed to apply a flat credit rate to all Wisconsin retail sales for 2011 in order to refund the 2010 over-collections.

While the Citizens' Utility Board (CUB) did not oppose applying the 2010 fuel cost credit to the 2011 revenue deficiency, some intervenor groups preferred that the 2010 fuel cost credit not be offset against the 2011 revenue deficiency. The Wisconsin Industrial Energy Group (WIEG) and Wausau Paper requested that the credit be returned to customers immediately, but if the Commission chose to offset the 2010 fuel cost credit against the 2011 revenue deficiency, then WPSC's 2010 fuel cost overcollections should be allocated to customer classes and applied to customer bills on the basis of energy usage.

Offsetting the 2010 fuel credit against the 2011 electric utility revenue deficiency helps maintain rate stability and may prevent the customer confusion that could result if the Commission were to authorize a large electric utility fuel cost credit immediately followed by an electric rate increase. Therefore, the Commission finds it reasonable to offset the 2010 fuel cost over-recoveries against the 2011 electric revenue deficiency, by allocating the fuel refund to customer classes on the basis of energy use during the test year, and showing it as a separate per kWh line item credit on customer bills. Any remaining fuel cost over-recoveries will be returned to customers in an additional one-time credit as soon as practicable after actual 2010 monitored fuel costs are known.

Income Statement

Fuel Costs

Weston 4 - Excessive Exfoliation

Weston 4 is a supercritical 515 megawatt (MW) coal-fired plant owned by WPSC and Dairyland Power Cooperative (DPC). WPSC owns 70 percent of Weston 4, and DPC owns the remaining 30 percent. WPSC is the operating partner for the facility. On October 7, 2004, the Commission issued a Certificate of Public Convenience and Necessity (CPCN), in docket 6690-CE-187, authorizing the construction of the Weston 4 Power Plant. WPSC completed construction of Weston 4 and commenced generation on a test basis in January 2008. WPSC first became aware of the problem with excessive exfoliation at the similar, Millmerran, Australia, plant in 2004. The Australia plant and Weston 4 were built by the same boiler vender, Babcock and Wilcox (B&W).

Weston 4 began commercial operation in July 2008. In November 2008, the facility experienced a 13-day outage due to the plugging of its superheater tubing, caused by excessive exfoliation of magnetite that had formed on the inside of the superheater tubes. This outage was followed by another 20-day exfoliation-related outage that started in December 2008. In December 2008, B&W recommended that WPSC decrease the operating temperature of

Weston 4 in order to minimize the exfoliation problem. Decreasing the operating temperature of Weston 4 reduced its efficiency as the plant continued to burn the same amount of fuel, but produced less energy and capacity. Weston 4 has continued to experience exfoliation-related forced outages, most recently in August 2009, totaling 51 days of outages to date.

In February 2009, B&W informed WPSC that lowering the operating temperature of a supercritical plant like Weston 4 appeared to have no effect on the rate of magnetite formation and exfoliation. Accordingly, WPSC returned Weston 4 to its normal operating temperature. The current recommendation from B&W to address the exfoliation issue is for WPSC to follow a "seasoning" approach. Under this approach, Weston 4 will be shut down and restarted periodically. This "seasoning" is expected to allow magnetite build-up on the inside of tubing so as to allow exfoliation to occur in a controlled manner, thereby avoiding tube plugging and an extended outage. These planned outages will be utilized only if there has not been a forced outage that allowed the accumulated magnetite to be exfoliated. WPSC evaluated other options and has decided to follow the "seasoning" approach to manage the Weston 4 exfoliation issue. In addition to the forced outages referred to above, WPSC has had four two- to five-day exfoliation-related planned outages.

Commission staff and CUB both reviewed extensive documentation with respect to WPSC's actions in response to the excessive exfoliation issue. Commission staff also calculated the cost of replacement power that was subject to refund for the 2008 and 2009 forced outages and the cost of the scheduled exfoliation outages during 2010 and 2011. The total replacement power costs associated with these forced and planned outages was approximately $4.5 million.

Therefore, if the Commission were to determine that WPSC had not prudently responded to the Weston 4 exfoliation issue, it could have required refunds and disallowances up to $4.5 million.

As a result of his reviews of the documentation, exhibits, and testimony related to the exfoliation issue, CUB's expert witness concluded that WPSC had not prudently responded to the Weston 4 issue, and therefore, proposed requiring refunds of previously collected replacement power costs and disallowances of costs associated with the 2010 and 2011 scheduled exfoliation outages. Commission staff's review indicated that while WPSC could have been more proactive, its actions may not have been imprudent.

The Commission concludes that WPSC's actions were reasonable and prudent with respect to this issue, and therefore does not deny recovery of any of the replacement power costs associated with the exfoliation planned and forced outages. The Commission notes that WPSC reasonably relied on the expertise of its vendor in the selection of the tubing alloy and configuration. The Commission concludes that while WPSC could have been more proactive, it was not imprudent. The Commission also notes that even today the optimal alloy for use in the boilers of supercritical plants has not been identified.

Weston 4 - Additional Monitoring and Maintenance Work to be Done

CUB proposed that WPSC be required to perform inspections of the Weston 4 high pressure and intermediate pressure steam turbines during the next major outage and provide a report to the Commission on a schedule to be determined by the Commission. CUB expressed concern that a percentage of the exfoliated magnetite is passing through the steam headers into the high pressure and intermediate pressure steam turbines. CUB alleged that this exfoliated material could cause solid particle erosion on the turbine blades, leading to performance degradation of the steam turbine and loss of efficiency. CUB also raised concerns that solid particle erosion could reduce the mechanical integrity of the turbine blades and vanes, resulting in a turbine failure with weeks to months of downtime.

CUB further proposed that WPSC be required to inspect the Weston 4 superheater and reheater tubes for wall thickness, and provide comprehensive reports to the Commission on a schedule to be determined by the Commission. CUB raised concerns that there could be a long-term general thinning of the 347H tubing due to repeated oxidation and oxide exfoliation. Because the 347H tubes must maintain wall thickness to sustain pressure and meet the requirements of the National Board Inspection Code, CUB suggested that these tubes be inspected periodically and replaced if they become too thin. CUB further proposed that WPSC be required to install a "rainbow" of different alloys in the superheater for the purpose of evaluating the various alloys for resistance to magnetite deposition and exfoliation.

The Commission considers it unnecessary to require WPSC to perform any of the testing proposed by CUB. The Commission notes that a significant investment would be associated with the proposed testing, especially for the installation of the "rainbow" of various alloys in order to evaluate them for resistance to magnetite deposition and exfoliation. The Commission notes that WPSC has a significant investment in the Weston 4 plant, and that the Commission will be monitoring and evaluating the company's future actions with respect to this matter in future rate cases.

Weston 4 Equivalent Forced Outage Rate

In its CPCN application, WPSC estimated Weston 4's annual EFOR to be 6.7 percent, with a major (three-week) planned outage every 12 months. In its 2011 test year filing, WPSC used an estimated EFOR of 12.3 percent with a major (three-week) planned outage every 18 months. In its 2011 test year rate filing, WPSC assumed a higher forced outage rate, but with one week less of planned major outages per year, on average. Commission staff used a test year EFOR of 8.8 percent, with WPSC's updated, less frequent, major outage schedule, which results in annual plant availability that is the same as what was assumed in the CPCN application.

WPSC contended that the Commission should reflect its 2011 test year rate filing EFOR for Weston 4 in test year fuel costs. WPSC maintained that as a traditional rate-based unit, it did not guarantee Weston 4's performance as might have been the case had a proposed leased generation or a fixed rate approach been proposed. WPSC also indicated that if the Commission does hold WPSC to the CPCN EFOR, fairness would dictate that it receive the benefit of Weston 4's higher than CPCN-estimated capacity.

CUB supported Commission staff's adjustment to the Weston 4 EFOR, stating that ratepayers have a right to rely on the estimates put forward by utilities in CPCN applications, particularly because WPSC's alleged imprudence led to Weston 4 not achieving the outage rates put forward in its CPCN application. Commission staff, however, viewed the change in the forced outage rate to be a change in estimate, not a change due to any alleged imprudence, with respect to the Weston 4 plant.

The Commission finds that while it is not prepared to say that utilities should never be held to their CPCN estimates, in this case there is more current and reliable information with respect to forced outage rates, and imprudence was not a factor. Therefore, the Commission determines that WPSC's 2011 test year rate filing EFOR of 12.3 percent is reasonable.

Spot Coal and Natural Gas Prices

At the time of its audit, Commission staff believed that 2011 NYMEX natural gas futures and consultant estimates did not properly reflect the loss in demand for energy that has occurred in 2010. Therefore, Commission staff estimated 2011 spot coal and natural gas costs by adding 15 percent of the difference between the 2010 and 2011 coal and natural gas prices, to 2010 prices, to develop its estimate of 2011 spot coal and natural gas prices. (The 15 percent "adder" was used to reflect some recovery in demand for energy in 2011.)

At the time of both the hearing and Commission decision in this docket, there was very little difference between 2010 actual and 2011 futures prices for coal and natural gas. Commission staff viewed this to show that the market appears to be reflecting the decreased demand for energy that has been observed recently, and using 2011 futures prices and consultant estimates for spot coal and natural gas prices is reasonable. Noting that there was no longer any disagreement in this area, the Commission accepts the use of 2011 futures prices and independent consultant estimates for natural gas and spot coal prices, respectively.

Outside Attorney Fees

In docket 6690-UR-118, the Commission ordered WPSC to investigate pursuing insurance recoveries and legal actions against its rail carrier with respect to the carrier's failure to deliver coal during 2005. WPSC was to refund any settlements received, net of the legal fees and other costs incurred in obtaining these settlements. In its initial brief, CUB requested that WPSC be denied recovery of its attorney fees associated with obtaining the rail settlement, noting that the overall amount seemed high.

The Commission allows recovery of WPSC's full request for outside attorney fees in this matter, noting that the cost recoveries exceeded the cost of securing those recoveries. Commissioner Azar dissents and would have reduced, but not eliminated, recovery of these attorney fees.

Monitoring of Electric Fuel Costs

Monitored fuel costs include only the cost of fuel itself and purchased power energy. The following costs are excluded from monitoring and may only be adjusted in a base rate case:

1. purchased capacity costs that are required to meet reserve requirements;
2. firm transmission costs associated with these capacity purchases;
3. fuel and ash handling costs; and
4. sulfur dioxide (SO_2) allowance costs.

Based on information in the record, a reasonable test year monitored fuel cost is $334,100,000. The test year fuel cost divided by the test year estimate of net native energy requirements of 14,754,927 megawatt-hours (MWh) results in an average net fuel cost of $0.02264 per kWh. Appendix D shows the monthly fuel costs to be used for monitoring purposes.

Monitoring Ranges

It is reasonable to use the following fuel monitoring ranges for WPSC: (1) for the annual range, plus or minus 2 percent; (2) for the monthly range, plus or minus 8 percent; and (3) for the cumulative range, plus or minus 8 percent for the first month of the year, plus or minus 5 percent for the second month, and plus or minus 2 percent for the remaining months of the year.

New Fuel Rules

The Commission finds the fuel monitoring cost of $334,100,000 and $0.02264 per kWh approved in this rate case is the appropriate fuel cost for the approved fuel cost plan under a new fuel rule if the new rule is effective for calendar year 2011. The actual fuel cost shall be based on the same definition of fuel costs as determined in this proceeding. The annual fuel bandwidth shall remain at plus or minus 2 percent under the new fuel rule.

Incentive Compensation

WPSC compensation programs include both base pay and annual incentives. WPSC's cash compensation goal is to pay its employees a total cash compensation package (base pay plus target incentive pay) that is anchored to market median levels, as compared to compensation levels at other energy industry companies.

WPSC offers two cash incentive plans. One plan is the Integrys Executive Plan, which covers the top executives of Integrys and its subsidiaries, including WPSC. The second plan is the Integrys Non-Executive Plan, which covers non-union employees of Integrys and various subsidiaries, including WPSC. WPSC included both incentive plans' costs in electric and natural gas revenue requirements. WPSC subsequently requested recovery of $2,644,667 for incentive compensation equating to an additional 2.25 percent of non-executive O&M expense-related pay based on the Commission's Final Decision in docket 6690-UR-116.

Commission staff excluded all payroll dollars associated with WPSC's executive incentives and goal sharing, consistent with the decisions made in recent rate cases for other large investor-owned utilities in which the costs associated with incentive pay plans were not included in revenue requirements.

WPSC maintained that offering only base pay plans, without an incentive pay component, would make it more difficult for WPSC to attract the quality of employees required to provide a superior level of service to customers. According to WPSC, customers benefit by WPSC maintaining and improving productivity and quality of work performed, which in turn reduces overall costs to customers.

Although a portion of these incentives were previously approved in docket 6690-UR-116, the Commission now excludes these costs from revenue requirement. During these difficult economic times, it is appropriate for the Commission to limit the financial impacts on ratepayers.

Additional Adjustment to Test Year Forecasted Payroll Expense and Associated Payroll Tax

Commission staff proposed that the Commission could consider reflecting a 2.0 percent furlough adjustment or, alternatively, no wage increases for all non-union utility employees in the test year. This was also proposed in the current Madison Gas and Electric Company (MGE) rate proceeding.

The Commission acknowledges that WPSC has worked to reduce its costs. For the 2011 test year, however, the Commission finds that additional cost containment efforts are appropriate. The Commission finds it reasonable to incorporate the equivalent of a 1.0 percent furlough adjustment in the test year. The O&M labor expense impact, including payroll taxes, of a 1.0 percent reduction will reduce test year expenses by $1,248,000 for electric and natural gas operations.

The Commission also finds that WPSC management can decide how to best accommodate the revenue requirement reduction in a manner that does not harm the safety and reliability of the electric supply system. Accommodating this reduction may or may not include a furlough.

Test Year Operating and Maintenance Expense Reductions

WIEG proposed adjustments to six O&M expense accounts that were forecasted to increase significantly over the 2009 actual expense levels. The proposed adjustments to distribution maintenance expense, customer assistance expense, office supplies and expense, outside services employed expense, injuries and damages expense, and uncollectible expense were primarily based on recent two and three-year actual historical averages of the expenses for these accounts.

WIEG maintained that the Commission should not approve WPSC's forecasts of these costs, particularly where WPSC did not provide support in its testimony for the increase in costs. WPSC argued that WIEG provided no basis for disallowing these costs and supported Commission staff's audited and adjusted levels of these expenses which were based on information provided in response to Commission staff requests during its audit. Based on the audit conducted by Commission staff, the Commission concludes that it is reasonable to include Commission staff's forecasted levels of these expenses.

Pension and Benefits Costs

Commission staff included an adjustment adding $1,500,000 in 2011 electric and natural gas test year revenue requirement for recent health care legislation signed into law in March 2010, of which $1,072,000 was for high-cost health plans. During its audit, Commission staff considered whether the health care plan design should be changed or that the incremental costs for excise tax on the high-cost health plans should be paid for by the retirees receiving the benefit or by shareholders rather than ratepayers.

WPSC argued that it is not appropriate to disallow the incremental costs associated with the non-deductible federal excise tax on high cost health plans because the timing of the new health care legislation left insufficient time to make plan design changes, including the renegotiation of union contracts. Generally accepted accounting principles (GAAP) require that the cost of post-retirement benefits be calculated using current plan design and law.

Since WPSC could not make changes to its high cost health care plans in time for the 2011 test year filing, the Commission finds it reasonable to include these costs in the 2011 test year revenue requirements for electric and natural gas operations. The allowance of these costs is primarily based on timing. WPSC will have adequate time to adjust its health care plans before its next rate proceeding.

Deferred Pre-Construction Costs Associated with the High Country Wind Generation Project

Commission staff decreased electric amortizations by $232,931 to eliminate the recovery of $465,863 of deferred pre-construction costs amortized over two years for the High Country Wind Energy project (High Country) that WPSC no longer intends to build and own. Past Commission policy has been to exclude pre-construction costs until the Commission grants construction authorization. Since WPSC no longer intends to go forward with this project, the onus is on WPSC to support recovery of these costs. Commission staff also argued that the Commission could consider disallowing all or part of the pre-construction costs based on materiality and an earnings test in the respective years during which the costs were incurred.

The Commission finds that the evidence in this proceeding shows WPSC engaged in a thoughtful process in initially pursuing the High Country project and then a reasoned decision to terminate it. It is therefore reasonable to include $231,500 of amortization expense in electric test year 2011 revenue requirement. This amount represents one-half of the total deferred amount audited by Commission staff of $463,000 amortized over 2011 and 2012. Commissioner Azar dissents.

Other Deferrals

As a result of the ratemaking process, utilities sometimes include allowable costs in a period other than the period in which those costs would be charged to expense by an unregulated enterprise in accordance with GAAP. These differences usually relate to the timing of the recognition of a cost. The result of these timing differences is the creation of deferred accounts.

As discussed above, the Commission's policy on deferred accounts is set forth in the Commission's Statement of Position, SOP 94-01. Appendix E is a list of those deferred accounts approved for WPSC, the amortization period, and the amount of Wisconsin jurisdictional 2011 test year amortization expense. It is appropriate to begin recording test year escrowed conservation amortizations, additional Focus on Energy payments, and the amortization of the 2009 RSM adjustment as of the effective date of this Final Decision. It is appropriate to treat all other amortizations as normal test year expenses by recording the full amounts in the test year.

Revenue Stabilization Mechanism Caps (Hard Caps vs. Earnings Cap)

In docket 6690-UR-119, the Commission approved the Energy Efficiency Stipulation between CUB and WPSC, which included the RSM for residential and small commercial customers. The Commission imposed a number of conditions in its approval of the RSM, including caps on the annual revenue adjustments of $12 million for electric and $4 million for natural gas, which were approximately equal to 100 basis points of the return on equity. In response to a Request for Rehearing made by WPSC, the Commission increased the caps to $14 million annually for electric and $8 million for natural gas.

In this proceeding, WPSC proposed that these "hard caps" on the annual revenue adjustments be replaced with an earnings cap on WPSC's electric and natural gas operations for 2011 and 2012. WPSC argued that the current caps result in a disincentive for it to increase commitments to conservation and energy efficiency programs once the caps are reached. Under WPSC's proposal, each annual revenue adjustment would be capped at the amount which would result in the utility earning its authorized return on equity for its Wisconsin retail operations in that year. That is, the annual revenue adjustment would be limited to any excess or deficiency in earnings above or below the authorized return. The deficiency or surplus in earnings would be calculated under GAAP and determined by WPSC's external auditor "without further adjustment."

The RSM has been in place for two years of its planned four-year pilot. The Commission finds that it is inappropriate to make such a significant change to the caps when WPSC is only half way through the four-year pilot. In addition, revising the caps on the annual adjustment as proposed by WPSC could result in an unintended incentive for it to exceed budgeted spending in other areas with the promise of recovery through the RSM adjustment.

Energy Efficiency

Customer Service Conservation

WPSC's proposed 2011 natural gas and electric customer service conservation activities consist of energy efficiency information services for residential, commercial, and industrial customers, its Farm Wiring Assistance Program, research dollars for Energy Center of Wisconsin dues, partnering with the Electric Power Research Institute, and providing for general energy efficiency support and administration. These activities are essentially the same as its 2010 activities, which the Commission determined to be appropriate in docket 6690-UR-119. While

WPSC's proposed 2011 customer service conservation and load management activities are appropriate, another review of these activities may be needed before WPSC's next rate proceeding.

The minimum level of customer service conservation and load management spending for WPSC was established in the Commission's 2001 order in docket 5-BU-100. The Commission's 2001 order did not define customer service conservation and load management activities and did not provide direction for alignment of these activities with statewide energy efficiency programs. Given the increased funding for statewide energy efficiency and renewable resource programs as a result of Act 141, and the potential for additional funding increases in the future, it may be appropriate for the Commission to explore policy options to better align docket 5-BU-100 expenditures and activities with current statewide program goals and funding.

If the Commission chooses to address this issue before WPSC's next rate proceeding, it is appropriate for WPSC to work with Commission staff to review its customer service conservation and load management activities to determine if they are still appropriate and propose any changes needed to meet the Commission's policy objectives. If WPSC's customer service conservation activities are modified as a result of any Commission action regarding the appropriate use of customer service conservation and load management dollars, WPSC should also propose modifications to its measures of success consistent with Commission policy and proposed changes in activities.

Weston 4 Programs

The Commission's October 7, 2004, Final Decision in docket 6690-CE-187 required WPSC to capture 32 MW of energy efficiency by the end of 2009, above that achieved through statewide energy efficiency programs. The Weston 4 programs were implemented to meet that order requirement. The Weston 4 programs consisted of both utility-delivered load management and energy efficiency programs and also a contract for 10 MW of savings with Wisconsin Energy Conservation Corporation, the Focus on Energy Program Administrator for residential and business programs. The Weston 4 programs are referred to as ordered programs in Act 141. WPSC/Focus on Energy substantially achieved the 32 MW goal by the end of 2008 and the programs terminated on December 31, 2008.

As ordered programs in Act 141, the expenditures for these programs were included in the Act 141 required energy efficiency expenditure amount. The 2008 and 2009 contributions by WPSC to the Statewide Energy Efficiency and Renewable Administration (SEERA) for statewide programs were adjusted based on WPSC's estimated Weston 4 expenditures. Because Act 141 requires each utility to spend 1.2 percent of operating revenues on qualifying programs, any dollars budgeted for Weston 4 programs in 2008 and 2009 that were not spent on these programs are required to be remitted to SEERA. To ensure compliance with Act 141, it is appropriate for WPSC to file with the Commission a final report of its Weston 4 programs. The report should include final achievement towards goals and audited expenditures. If it is determined that any of the dollars budgeted for Weston 4 programs in 2008 and 2009 were not spent, WPSC should work with Commission staff and SEERA to remit these funds.

Load Management Incentive

WPSC proposed that it should be granted a bonus of $4.8 million, which represents approximately 40 basis points of additional return on equity, as an award and incentive to recognize its load management programs and activities. WPSC asserts that it is a national leader in the implementation of load management programs, that its load management programs have negated the need for a substantial amount of generating capacity and that its shareholders have lost significant investment opportunities as a result. WPSC argues that its proposed bonus would provide an incentive for it to maintain and expand its load management programs.

The Commission recognizes the value that WPSC's load management programs have provided, but does not find that it would be reasonable to approve the bonus and incentive it proposed.

Conservation Budget and Escrow Adjustment

WPSC filed a proposed 2011 conservation budget of $26,431,263 in revenue requirement exclusive of additional payments to Focus on Energy for the Energy Efficiency Stipulation as approved in docket 6690-UR-119, with $17,436,893 allocated to electric operations and $8,994,370 allocated to natural gas operations. Commission staff's analysis of conservation expenses included reviewing the proposed test year conservation expenditures, forecasting the over-spent balance in the conservation escrow at the beginning of the test year, and reviewing WPSC's forecasted amortization expense associated with previously escrowed conservation expenditures. As a result of this analysis, Commission staff forecasted a $1,053,747 over-spent balance at January 1, 2011, for electric operations and a ($3,061,195) under-spent balance at January 1, 2011, for natural gas operations. The Commission staff forecasted revenue requirement includes the amortization of the estimated over-spent and under-spent balances over the two-year biennial period 2011 and 2012, or $526,873 test year amortization of the estimated electric over-spent balance and a ($1,530,597) test year amortization of the estimated natural gas over-spent balance.

The reasonable level of expensed conservation costs recoverable in rates for the 2011 test year is $17,963,766 for electric utility operations and $7,463,773 for natural gas utility operations. The level for electric utility operations consists of the conservation budget of $17,436,893, and an escrow adjustment of $526,873. The electric escrow adjustment represents the test year amortization of the projected overspent escrow balance at December 31, 2010, over two years. The level for natural gas operations consists of the conservation budget of $8,994,370, and an escrow adjustment of ($1,530,597). The natural gas escrow adjustment represents the test year amortization of the projected underspent escrow balance at December 31, 2010, over two years.

Energy Efficiency Stipulation Funding

The Energy Efficiency Stipulation approved in docket 6690-UR-119 requires WPSC to increase its commitment to Focus on Energy, for the years 2009 through 2012, above the 1.2 percent of operating revenues required by Act 141. According to the Energy Efficiency Stipulation, WPSC is to contribute 3.0 percent of both natural gas and electric operating revenues in 2011.[1] CUB proposed that WPSC's 2011 and 2012 Focus on Energy contributions remain at the 2010 level of 2.5 percent of operating revenues. CUB contends that the Energy Efficiency Stipulation approved by the Commission was based on anticipated increases in the overall Focus on Energy budget that have not occurred. CUB believes that increasing WPSC's contribution above the 2.5 percent level could harm overall Focus on Energy efforts if resources are diverted to the WPSC territory-wide programs.

In 2010, WPSC is contributing about twice the amount of funds to Focus on Energy as other investor-owned utilities. This is expected to increase to about three times the level of other

[1] The funding for energy efficiency programs under the Energy Efficiency Stipulation is 3.0 percent in 2011 and is calculated on the three-year average electric and natural gas revenues from participating residential and commercial rate classes.

investor-owned utilities in 2011 if WPSC contributes the 3.0 percent of operating revenues specified in the Energy Efficiency Stipulation.

The Commission approved the Energy Efficiency Stipulation pilot, in part, based on the energy efficiency benefits to participating ratepayers. While the Energy Efficiency Stipulation results in WPSC's contribution to Focus on Energy being higher than that of other investor-owned utilities, WPSC's total 2010 energy efficiency commitment was not substantially higher than that of several other utilities with voluntary utility programs.

WPSC's total 2010 energy efficiency budget, as a percent of revenues, is about 2.7 percent. Wisconsin Power and Light Company's (WP&L) 2010 energy efficiency is about 2.8 percent of revenues, and Wisconsin Electric Power Company's (WEPCO) is about 2.3 percent of revenues. Additionally, increases in the overall Focus on Energy funding level are anticipated for 2011 and 2012. This increase in Focus on Energy funding would increase the Focus on Energy contributions of all investor-owned utilities other than WPSC.

To ensure WPSC ratepayers participating in the Energy Efficiency Stipulation pilot are provided sufficient benefits through energy efficiency to outweigh the potential ratepayer costs, it is appropriate for WPSC's contribution to Focus on Energy for those ratepayers participating in the Energy Efficiency Stipulation pilot to be consistent with the approved Energy Efficiency Stipulation. WPSC should contribute 3.0 percent of natural gas operating revenues that are generated from participating residential and commercial rate classes in 2011 and 2012. WPSC should contribute 3.0 percent of electric operating revenues in 2011 and 3.5 percent in 2012. This will result in additional energy efficiency funding in 2011 of $11,735,383 by the electric utility and $7,276,790 by the natural gas utility.

Summary of Operating Income Statements at Present Rates

In addition to the findings regarding the specific items discussed in this Final Decision, all other uncontested Commission staff adjustments to WPSC's filed operating income statements are appropriate. Accordingly, the estimated Wisconsin retail electric and natural gas utility operating income statements at present rates for the 2011 test year, which are considered reasonable for the purpose of determining the revenue requirements in this proceeding, are as follows:

	Electric (000's)	Natural Gas (000's)
Operating Revenues		
Sales of Electricity	$951,324	$ ---
Sales of Natural Gas Including Transportation	---	372,794
Other Operating Revenues Including Opportunity Sales	39,814	2,326
Other Income - Before Tax	208	---
Total Operating Revenues	$991,346	$375,120
Operating Expenses		
Fuel and Purchased Power	$391,021	$ ---
Purchased Gas Expense	---	220,953
Other Production Expenses	71,688	617
Transmission Expenses	99,202	---
Distribution Expenses	43,025	20, 200
Customer Accounts Expenses	15,167	11,556
Customer Service Expenses	33,608	16,634
Sales	0	0
Administrative & General Expenses	90,897	28,662
Total Operation & Maintenance Expenses	$744,608	$298,622
Depreciation Expense	71,819	15,566
Amortization Expense	18,740	7,107
Taxes Other Than Income Taxes	35,808	5,721
Income Taxes	29,768	15,713
Total Operating Expenses	$900,743	$342,729
Net Operating Income	$90,603	$ 32,391
Adjustments to Net Operating Income	(694)	(9)
Adjusted Net Operating Income	$89,909	$ 32,382

Average Net Investment Rate Base

Summary of Average Net Investment Rate Bases

All uncontested Commission staff adjustments to WPSC's filed average net investment rate bases are appropriate. Accordingly, the estimated Wisconsin retail electric and natural gas utility average net investment rate bases for the 2011 test year, which are considered reasonable for the purpose of determining the revenue requirements in this proceeding, are as follows:

	Electric (000's)	Natural Gas (000's)
Utility Plant in Service	$2,558,086	$687,251
Less: Accumulated Reserve for Depreciation	1,307,927	366,602
Net Utility Plant	$1,250,159	$320,649
Add: Natural Gas in Storage	---	26,429
Fuel Inventory	33,192	---
Materials and Supplies	24,275	1,854
Other Investments - net of tax	1,095	---
Other Deferred Income Taxes	6,159	(255)
Less: Customer Advances – net of tax	20,878	2,006
Average Net Investment Rate Base	$1,294,002	$346,671

Pro Forma Rate of Return

The adjusted net operating income at present rates for purposes of this proceeding for the test year ending December 31, 2011, results in a rate of return on average net investment rate base of 6.95 percent for Wisconsin retail electric utility operations and 9.34 percent for Wisconsin retail natural gas utility operations.

Financial Capital Structure and Dividend Restriction

The long-term range for WPSC's common equity ratio, on a financial basis, as stipulated to in WPSC's last rate case, was 49 to 54 percent common equity, while the target level for the test year common equity was 51 percent. Neither the stipulated range nor target test year average was contested in this docket. However, an issue in this docket relating to the holding of excess temporary investments results in a test year average equity ratio less than the target, but still within the reasonable range.

In its filing, WPSC requested additional expenses related to the expansion of its credit facilities, which provide liquidity to its commercial paper program, as well as the execution of a second facility, while forecasting minimal borrowing through the program. In addition, WPSC forecasted the refinancing of $150 million of maturing long-term debt with additional long-term debt, while also forecasting temporary cash investments averaging in excess of $40 million. Commission staff's audited test year resulted in less commercial paper borrowing and additional temporary cash investments.

The Commission has in the past addressed the issue of excess temporary cash investments. In its February 27, 1980, *Findings of Fact and Final Order* in docket 6650-GR-6, the Commission determined that temporary cash investments not required for utility operations should be assigned to common stock equity. In such a case, the temporary cash investment would remain in the financial capital structure, but be removed from the common equity component in the regulatory capital structure, as is done for all other utility-owned non-utility assets. In addition, in recent years, the Commission has restricted inclusion of equity infusions intended to maintain WPSC's target common equity level when such equity infusions result in excess temporary cash investments.

This Commission remains committed to financially healthy utilities, and several alternatives, including those discussed above, were reviewed for their impacts on WPSC's capitalization. Taking into consideration the current circumstances, the appropriate alternative is to exclude the long-term debt from the test year forecast. In addition, special dividends and equity infusions shall be forecasted to address the excess temporary cash investment while also addressing the need to maintain an adequate common equity level. Removing the long-term debt issuance from the test year, WPSC forecasted commercial paper borrowing increases to support allowing the additional expenses relating to a moderate expansion of its credit facilities, but not for the establishment of a second credit facility.

In calculating capital structures, on a financial basis, the Commission has imputed debt associated with obligations not reported on balance sheets. The imputed debt results in additional costs to ratepayers because the utility is required to add sufficient common equity to maintain its target equity level, and the higher return earned on the additional equity increases the weighted cost of capital. In addition, imputing debt for off-balance sheet obligations is not a common practice of other state utility commissions. The Commission finds that it is not obligated to adopt the risk assessment of an outside rating agency. Instead, the Commission will independently examine off-balance sheet obligations based on its assessment of risk.

To independently examine off-balance sheet debt obligations, it is reasonable to require that WPSC submit detailed information regarding all off-balance sheet obligations for which the financial markets will calculate a debt equivalent. The information shall include, at minimum: (1) the minimum annual lease and PPA obligations; (2) the method of calculation along with the calculated amount of the debt equivalent; and (3) supporting documentation, including all reports, correspondence and any other justification that clearly established Standard & Poor's (S&P) and other major credit rating agencies' determination of the off-balance sheet debt equivalent, to the extent available, and publicly available documentation when S&P and other major credit rating agencies documentation is not available.

For the test year, the Commission finds it reasonable to impute an aggregate $120,631,000 of debt equivalent. Of this amount, $4,309,000 is relating to non-purchased power operating leases which include a Commission staff correction to WPSC's imputation and $8,282,000 of subsidiary debt related to WPSC's subsidiary, WPS Leasing. The operating lease imputation is based on 100 percent of the present value of the payment streams, while the subsidiary debt is the forecasted average principal outstanding for the test year.

An additional $107,998,000 of imputed debt relates to PPAs and includes $82,746,000 of uncontested debt equivalence for contracted capacity payments. The imputation is based on a 40 percent risk factor applied to the present value of the payment streams. Contested were the calculations for WPSC's Manitoba Hydro and KNPP PPAs. For the Manitoba Hydro PPA, the Commission finds the amount of $1,123,000, based on a proxy capacity payment associated with the contract minimum and a 25 percent risk factor adjustment to be reasonable. Use of a 25 percent risk factor reflects that the expense is recovered through the fuel clause.

The Commission also finds it reasonable to use the proxy capacity payment methodology for the KNPP PPA, producing a debt equivalent of approximately $24,129,000. This method is consistent with that used for WP&L's KNPP-related PPA in docket 6680-UR-117 and WEPCO's Point Beach Nuclear Power Plant PPA in docket 5-UR-104.

Also contested in this case was the issue of debt imputation relating to wind, parallel generation, and RPS PPAs and to wind-related land leases. The issues of wind-related PPAs and wind-related land leases were litigated in dockets 6680-UR-117 and 5-UR-104, as well as MGE's rate case in docket 3270-UR-116. Consistent with its treatment in those dockets, the Commission determines that no debt imputation should be included for wind, parallel generation, and RPS

PPAs. The Commission determines that the debt imputation for the wind-related land leases shall be based on the lesser of the present value of the payments, assuming continued operation of the wind turbines, and the present value of the termination payments, if the operation is discontinued. If no termination payment is required, it is appropriate to use one year's payment as the proxy termination payment. Commissioner Azar dissents on the issue of the imputation of the wind-related land leases.

Lastly, neither WPSC nor Commission staff included debt imputation associated with obligation categories of advances from affiliated companies, affiliated capital leases, purchased power capital leases, guarantees, underfunded pension and other post-retirement employee benefit plans, and asset retirement obligations. For each of the above categories, either WPSC does not have any obligations or the Commission has previously determined not to include debt imputations for the category.

Incorporating the above off-balance sheet debt equivalents and other Commission determinations, WPSC's financial capital structure for the test year will consist of 50.24 percent common equity, 2.45 percent preferred stock, 38.99 percent long-term debt, 2.56 percent short-term debt, and 5.76 percent off-balance sheet obligation debt equivalents, including subsidiary debt. The 50.24 percent common equity, on a financial basis, falls within the common equity guideline of 49 to 54 percent.

Assessing the reasonableness of WPSC's capital structure depends upon three important principles. First, capital structure decisions must be based on WPSC's needs, not on the needs of the non-utility operations of the holding company. Second, the capital structure should provide adequate flexibility for WPSC and the Commission to allow proper utility investment now and in the future. Third, the dividend policy of WPSC should be similar to typical electric utility dividend practices as long as WPSC is below the estimated test year common equity ratio.

Generally, under Wis. Stat. § 196.795, the utility's capital needs must take precedence over non-utility needs in order for ratepayers to be protected. The identification of utility needs goes beyond foreseeable needs. WPSC must have flexibility to finance both foreseen and unforeseen capital requirements.

In previous dockets, the Commission recognized the need to protect ratepayers and to ensure that utility needs are placed before non-utility needs in capital structure and dividend policy choices. Consequently, WPSC shall not pay, without Commission approval, normal dividends greater than 103 percent of the prior year's common dividend. WPSC shall notify the Commission if any special dividend is contemplated. No special dividend that might cause the common equity, on a financial basis as calculated in this Final Decision, to drop below the projected calendar year average of 50.24 percent or the dollar amount of equity reflected in the test year, is permitted without Commission approval.

Ten-Year Financial Forecast

WPSC's ten-year financial forecast is useful to the Commission and should be submitted in future rate cases. The ten-year forecast may be combined with other business risk information to assess capital structure needs and rate of return requirements.

Regulatory Capital Structure and Cost of Capital

As in the previous rate case docket, in order to arrive at the common equity amount for WPSC's regulatory capital structure, Commission staff deducted WPSC's investment in the common equity of American Transmission Company LLC (ATC), net of deferred income taxes associated with transmission assets transferred to ATC, along with other non-utility items, from booked common equity. Consequently, a reasonable utility rate making capital structure for the purpose of establishing just and reasonable rates for the test year consists of 51.65 percent common equity, 2.69 percent preferred stock, 42.85 percent long-term debt, and 2.81 percent short-term debt.

Short-Term Debt

WPSC's test year capital structure contains approximately $53.5 million of short-term debt, of which $10 million is through a master note and $43.5 million is through commercial paper. A reasonable estimate of WPSC's average cost of short-term debt through the master note for the test year is 0.43 percent. A reasonable estimate of WPSC's average cost of short-term commercial paper debt for the test year is 0.58 percent. These forecasts are based on the average of test year London Interbank Offered Rate (LIBOR) and commercial paper rate estimates, respectively, provided by the *Blue Chip Financial Forecasts* newsletter. This is a reasonable and objective method of determining WPSC's short-term debt costs.

Long-Term Debt

WPSC's test year capital structure contains on average, $815.9 million of long-term debt. A reasonable estimate for the embedded cost of long-term debt is 5.59 percent for the test year.

Preferred Stock

The average cost of preferred stock is 6.08 percent for the test year.

Return on Common Equity

The principal factor used to determine the appropriate return on equity is the investors' required return. Authorized returns less than the investors' required return would fail to compensate capital providers for the risks they face when providing funds to the utility. Such sub-par returns would make it difficult for a utility to raise capital on an ongoing basis. On the other hand, authorized returns that exceed the investors' required return would provide windfalls to utility investors as they would receive returns that are in excess of the necessary level. Such high returns would be unfair to utility consumers who ultimately pay for those returns.

In reaching its determination as to the appropriate return on equity, the Commission must balance the needs of investors with the needs of consumers, with due consideration to economic and financial conditions along with public policy considerations. If the investors' required return could be measured precisely, setting the authorized return would be straightforward. Because that return cannot be measured precisely, determining the appropriate return on equity is typically one of the most contested issues in a rate proceeding such as this one.

In this proceeding, WPSC proposed an increase in its current authorized return to 11.25 percent. WIEG, CUB, and the Wisconsin Paper Council supported a decrease in the authorized return, recommending that the return on equity be set at no higher than 9.75 percent. Commission staff suggested that the appropriate return on equity be set somewhere in the range from 10.0 to 10.6 percent and used 10.3 percent. The revenue impact for each 10-basis points is approximately $1.4 million.

Given the above-mentioned considerations, balance is struck most reasonably in this proceeding by authorizing a return on equity capital of 10.3 percent. A 10.3 percent return should allow the applicant to attract capital at reasonable terms without unduly burdening consumers with excessive financing costs.

Accordingly, the average utility capitalization ratios, annual cost rates, and the composite cost of capital rate considered reasonable and just for setting rates for the test year are as follows:

	Amount (000's)	Percent	Annual Cost Rate	Weighted Cost
Utility Common Equity	$ 983,508	51.65%	10.30%	5.32%
Preferred Stock	51,188	2.69%	6.08%	0.16%
Long-Term Debt	815,850	42.85%	5.59%	2.40%
Short-Term Debt – Master Note	10,000	0.53%	0.43%	0.01%
Short-Term Debt	43,513	2.28%	0.58%	0.01%
Total Utility Capital	$1,904,059	100.00%		7.90%

The weighted cost of capital of 7.90 percent is reasonable for WPSC for the test year. It generates an economic cost of capital of 11.56 percent and a pre-tax interest coverage ratio of 4.78 times on the regulatory capital structure, and 4.53 times on the test year financial capital structure.

Rate of Return on Rate Base

The 7.90 percent composite cost of capital must be translated into a rate of return which can then be applied to the average net investment rate base and used to compute the overall return requirement in dollars. The estimate of WPSC's average net investment rate base plus CWIP and DEC for the test year is 102.43 percent of capital applicable primarily to utility operations plus deferred investment tax credits. This estimate reflects all appropriate Commission adjustments, and is a reasonable and just factor for use in translating the composite cost of capital into a return requirement applicable to the average net investment rate base.

To allow a test year current return on the average CWIP balance, an adjustment must be added to the return on net investment rate base. Given WPSC's financing and cash flow requirements in the test year and the forecasted amount of construction activity, the Commission finds it reasonable to allow a current return on 50 percent of CWIP for the test year.

Consistent with prior Commission decisions, it is reasonable to include adjustments to the return on net investment rate base to allow a current return on the unamortized balances of the DEC premium and KNPP non-qualified decommissioning trust fund at the authorized pre-tax weighted average cost of capital. In addition, it is reasonable to include adjustments to the return on net investment rate base to allow a current return on the unamortized balances of the KNPP contingent loss deferral and RSM deferral at the authorized short-term debt rate as authorized in dockets 6690-UR-117 and 6690-UR-119, respectively.

Accordingly, the Commission finds that the rates of return on average Wisconsin retail electric and natural gas net investment rate bases, which are reasonable for the purpose of determining just and reasonable rates in this proceeding, are as follows:

	Electric	Natural Gas
Weighted Cost of Capital	7.90%	7.90%
Ratio of Average Net Investment Rate Base Plus CWIP and DEC to Capital Applicable Primarily to Utility Operations Plus Deferred Investment Tax Credit	102.43%	102.43%
Adjusted Cost of Capital to Derive Percent Return Requirement Applicable to Average Net Investment Rate Base	7.71%	7.71%
Adjustment to Return Requirement to Provide Current Return on CWIP, DEC, and KNPP NQDT	0.15%	0.01%
Adjustment to Return Requirement to Provide Current Return on KNPP contingent loss, RSM, and High Country Pre-Construction at Composite short term debt rate	0.00%	0.00%
Required Rate of Return on Average Net Investment Rate Base	7.86%	7.72%

Revenue Requirement

On the basis of the findings in this Final Decision, a $5,758,000 increase in Wisconsin retail electric utility revenues and an $8,275,000 decrease in Wisconsin retail natural gas utility revenues are reasonable for the purpose of determining reasonable and just rates in this proceeding and are computed as follows:

	Electric	Natural Gas
Pro Forma Return on Average Net Investment Rate Base at Present Rates	6.95%	9.34%
Required Return on Average Net Investment Rate Base	7.86%	7.72%
Earnings Deficiency (Excess) as a Percent of Average Net Investment Rate Base	0.91%	(1.62%)
Average Net Investment Rate Base (000's)	$1,294,002	$346,671
Amount of Earnings Deficiency (Excess) on Average Net Investment Rate Base (000's)	$11,775	($5,616)
Revenue Deficiency (Excess) to Provide for Earnings Deficiency Plus Federal and State Income Taxes (000's)	$19,646	($9,370)
Adjustment to provide for Act 141 Large Customer Billing Limitations	$3,031	$1,515
Adjustment to Limit RSM Recovery	($1,680)	($420)
Adjustment to Include 2010 Fuel Refund	($15,239)	
Net Revenue Deficiency	$5,758	($8,275)

Electric COSS and Rates

Electric COSS

Witnesses for WPSC, the intervenors, and Commission staff testified regarding COSS issues and others factors to consider when allocating revenue. Discussions included the use of several different types of demand allocator and mix of demand and energy allocators for assigning production costs, the appropriate allocation of distribution costs, the allocation of RSM costs, and the appropriate allocation of final adjustments of fuel and other costs. The adverse impact of an increased electric rate on all customer classes was introduced as well. The Commission weighed the information provided in the testimony in making its decisions and assigning revenue responsibility and determines that it is appropriate for the Commission to continue to rely on the results of a variety of COSS information, along with other factors, such as bill impacts, when allocating revenue responsibility.

WIEG provided COSS that accounted for cost differences between single-phase and three-phase primary distribution circuits and stated that this approach provides a more accurate reflection of costs. The allocators used in this analysis were developed from assumptions concerning the WPSC system because this accounting system does not maintain the detail necessary to develop those allocators. WPSC stated that the method used by WIEG is not based on cost causation and is overly simplistic. WPSC also noted that the type of refinement needed in the accounting system could be obtained, but at great expense.

The Commission recognizes that COSS that better recognize single-phase and three-phase primary distribution circuit costs may be of some value when assigning revenue responsibility. The additional cost to achieve this value and the ability to use this cost information in the WPSC rate structure must also be considered. For these reasons, the Commission directs Commission staff to work with WPSC, intervenors in this case, and other major Wisconsin investor-owned utilities to explore this issue further.

Electric Revenue Allocation and Rate Design

The WPSC revenue to be collected in the test year consists of several major components: return on rate base, operation and maintenance costs, 2010 fuel credits, and recovering RSM dollars. The Commission recognizes that 2010 fuel credits should be allocated to classes on the basis of energy and the RSM recovery should be based on the Energy Efficiency Stipulation. After considering these factors, the Commission authorizes a final revenue reallocation and rate adjustments consistent with the types of cost changed by its determinations. The Commission approves an electric revenue allocation that results in a lower than average increase for the industrial use customer class, and a higher than average increase for the Small Use class which include residential, small commercial and lighting customers, and the medium commercial customer classes.

The Commission generally approves Commission staff's electric rate design as adjusted for the final revenue requirement. The Commission determines that the Cg-20 and Cp class rate changes should be structured in such a way that the changes reduce the adverse impact on the lower load factor customers of these classes.

The authorized revenue allocation and rate design for electric utility service is shown in Appendix B. Authorized Act 141 credits, the 2010 fuel credit, and RSM Surcharges are included in Appendix B.

The rates shown in Appendix B include an RSM Surcharge for the recovery of 2009 expenses in 2011. It is appropriate to direct that the Electric Revenue Stabilization Mechanism Schedule be updated to reflect the current test year and authorize a second set of rates to be effective on January 1, 2012, using the base rate set in this Final Decision.

WPSC proposed a number of changes in its tariff classes. These changes included changing language in the WPSC Response Rewards Program, creating a new comprehensive lighting tariff (Ls-1), eliminating the Residential and Commercial Space Heating and Cooling tariffs (RC-S1 and CG-S1), cancelling the General Water Heating tariff (GW-X), making other minor revisions to customer tariffs and rules, and authorizing changes in extension credits. The Commission has reviewed these changes and finds them to be reasonable.

The existing WPSC TOU rate offerings for residential customers include two-tier and three-tier pricing periods and a Response Rewards program. In this proceeding, WPSC asked to close the two-tier residential TOU tariff to new customers so that it could work to move existing two-tier TOU customers to the three-tier TOU offering and the Response Rewards program which better reflect costs incurred by the utility. The request is authorized and WPSC is directed to work with existing residential two-tier TOU customers on moving to the three-tier TOU offering and the Response Rewards program. Because WPSC does not currently have a three-tier TOU for its small commercial customers, it is also reasonable to direct WPSC to develop such an offering for presentation at the time of its next rate proceeding.

Customer-Owned Generation Tariffs

WPSC requested authorization to unbundle its existing PG-2 parallel generation tariff into three separate tariffs and to base buyback rates on Midwest ISO locational marginal prices (LMPs). WPSC argued that LMP based buyback rates would more accurately represent its true avoided cost, and that such a transition would reduce the potential for over- and under-payment for energy purchased from parallel generation customers. RENEW Wisconsin argued that LMP pricing is a poor proxy for the value of renewable energy from customers and fails to consider many externalized costs.

LMP is an appropriate proxy for utility avoided cost. WPSC's proposed LMP pricing of parallel generation tariffs is reasonable as this pricing is driven by the model of lowest substitutable cost and stands to benefit both the company and the ratepayer. Customers with renewable generation sources under the parallel generation tariffs may separately negotiate a renewable credit rate for any renewable energy sold to WPSC.

WPSC proposed modifications to its PG-4 net billing tariff to require net-metering customers to size their generation facilities to match their annual load requirements within the existing 20 kW limit, remove language for pre-1990 non-renewable resource contracts, and raise the threshold for issuing checks to customers from $25 to $100. Both RENEW Wisconsin and Commission staff proposed increasing the capacity limit of WPSC's net billing tariff from 20 kW to 100 kW. WPSC opposed this proposal, arguing that while WPSC may consider voluntarily increasing the capacity limit of its net billing tariff, the Commission lacks the authority to order such a change, citing preemption by FERC under the Public Utility Regulatory Policies Act (PURPA). WPSC further argued that an order by the Commission requiring it to increase the capacity limit of its net billing tariff would violate provisions of Act 141. WPSC requested in its comments on Commission staff's Briefing Memorandum that if the Commission determines to increase the capacity limit on this tariff, it limit net energy billing to the customer's usage in the applicable billing period, and provide that any net sales to the company are made pursuant to the PG-2 avoided cost tariff.

The Commission's authority over net billing is not preempted by FERC, but rather is explicitly recognized by PURPA, as amended by the Energy Policy Act of 2005. PURPA identifies net metering service as a standard, defined as "service to an electric consumer under which electric energy generated by that electric customer from an eligible on-site generating facility and delivered to the local distribution facilities may be used to offset electric energy provided by the electric utility to the electric consumer during the applicable billing period." 16 USC § 2621(d)(11). PURPA requires each state regulatory authority to consider the implementation of its ratemaking standards, including the above provision for net metering, "to the extent consistent with otherwise applicable State law." 16 USC § 2621.

In a Letter Order issued January 28, 1982, the Commission required that all utilities under its jurisdiction provide immediate implementation of net energy billing tariffs. At the time, the

Commission directed that these net billing tariffs be limited to electric generators rated at 20 kW or less. However, there is no state or federal statute that prescribes 20 kW as the limit for net billing.

Increasing the capacity limit on WPSC's net billing tariff also does not violate Act 141, as argued by WPSC. Wisconsin Stat. § 196.378(4m) declares that "the Commission may not impose on an electric provider any requirement that increases the electric provider's renewable energy percentage beyond that required . . . ." Under WPSC's proposed PG-4 tariff change requiring that customer-owned generation be "intended to offset a portion or up to all of the customer's requirements for electricity," a customer could, in principle, net its annual consumption at most down to zero. In practice, some small level of net sales to a utility may occur under net billing as discussed in the January 28, 1982, Letter Order. However, as WPSC's net billing tariff rules do not provide for the transfer of the renewable attributes of energy generated by customer-owned renewable sources even if some net sales to WPSC do occur, WPSC is not increasing its additional renewable energy percentage through net billing sales to the company.

In either case, WPSC is not obligated to increase its renewable energy percentage through the net billing tariff. Such an order could *decrease* the utility's renewable energy percentage, as pointed out by WPSC in its comments on Commission staff's Briefing Memorandum. This, however, does not violate Act 141, which only prohibits the Commission from taking action that would *increase* the utility's renewable energy percentage beyond that required by Act 141. A Commission order increasing the capacity limit on net billing service would not increase the utility's renewable energy percentage.

The Commission determines that WPSC's proposed Pg-4 tariff revisions are reasonable. In addition, it is reasonable to increase the capacity limit to 100 kW as such a change would accommodate small generator installations larger than the current 20 kW limit. Consistent with other changes to this tariff, eligibility for net billing is based on the customer's annual energy usage, with any excess amounts sold to the utility at the standard buyback rate.

Green Pricing Premium

WPSC offers a voluntary green pricing program that is marketed under the name NatureWise. In WPSC's previous rate case, the Commission approved an increase in the renewable energy premium to $1.25/100 kWh/month as a phased-in approach to align the premium with the incremental cost of acquiring renewable energy.

WPSC proposed increasing the charge for a 100 kWh block of energy purchased under its NatureWise tariffs from the current rate of $1.25 per block to $1.50 per block in order to recover more of the program's incremental costs which have risen due to decreases in WPSC's system cost of energy. Commission staff proposed to increase the premium to $2.40 per block in order to reflect the full estimated premium as calculated by WPSC. WPSC argued that increasing the premium beyond $1.50 per block would produce an unacceptable rate impact on current program participants and would undermine program participation. RENEW Wisconsin opposed any increase to the premium, arguing that an increase would be inappropriate as the cost of energy acquired to supply the green pricing program has not increased.

The Commission determines that it is appropriate for customers on WPSC's voluntary renewable energy tariff to pay the full incremental cost of renewable energy purchased through NatureWise. The full incremental cost is currently $2.40 per 100 kWh block. Additionally, transparent pricing of this program may lead to additional energy efficiency efforts as a reasonable and statutorily encouraged alternative. The Commission acknowledges that while the renewable energy premium does not, at this time, capture many externality costs such as environmental costs associated with fossil fuel-based generation that would drive down the cost of the renewable premium, it is not appropriate to address this issue in this proceeding.

Real Time Market Pricing

The Commission approved WPSC's Real Time Market Pricing rate schedule in WPSC's last rate case as a successor to its Generation Displacement Service rate schedule. Generation Displacement Service allowed industrial customers with generation the ability to purchase non-firm electric energy from the company at a small mark-up when it was less expensive than the customer's generation.

The current Real Time Market Pricing rate schedule allows customers to purchase energy at the LMP in the WPSC load zone with a $1/MWh adder. There is also a charge of $2.59/kW per month to recover transmission costs.

In order to transform the Real Time Market Pricing rate schedule into an alternative to its interruptible rate schedule, WPSC proposed several significant changes, including an increase from $1/MWh adder to $10/MWh to make the rate revenue neutral with respect to the interruptible tariff, and an increase in the transmission charge from $2.59 to $3.20/kW.

WIEG opposed the proposed changes. WIEG argued that because the $10/MWh adder is not based on cost, it should remain at $1/MWh. WIEG also proposed that the transmission charge should be calculated after the fact for each customer and be based on actual transmission charges from ATC. Finally, WIEG expressed concerned about the loss of a customer's eligibility to return to the interruptible rate schedule if a customer was to transfer to the Real Time Pricing Rate Schedule. WIEG posited that this could occur when a customer transfers from the interruptible rate schedule that is subsequently closed, and then as a result, the customer is unable to transfer back to interruptible service. Finally, WIEG expressed concern that the 90-day cancellation provision of the Real Time Market Pricing Tariff is not consistent with the annual April 15 nomination deadline for the interruptible rate schedule.

The Commission finds that the proposed changes to the Real Time Market Pricing Tariff are reasonable. The proposed $10/MWH adder is reasonable because it provides for the recovery of costs which do not change if a customer switches from the interruptible rate schedule to the Real Time Market Pricing rate schedule. The determination of transmission charges in advance is consistent with the determination of transmission costs for other rate schedules and reduces risk for participating customers because they can determine the cost of their transmission charges in advance, rather than after the fact. The Commission also finds that it is reasonable for the utility to allow customers to return to the interruptible rate schedule regardless of the standard April 15 nomination deadline for that rate schedule if a customer has been on the Real Time Market Pricing Tariff for at least one year.

Increase to the Interruptible Credit

WIEG proposed that the interruptible credit should be increased by 1.5 times any percentage increase in the firm demand charge. WIEG asserted that the interruptible credit has not been increased since 2005 even though the cost of constructing peaking capacity has increased since that time. WPSC, CUB, and Commission staff opposed increasing the interruptible credit due to the significant amount of excess capacity that exists in the Midwest ISO region and the current low market price of capacity. Because of these factors, the Commission finds that it would not be reasonable to increase the interruptible credit at this time.

Natural Gas COSS and Rates

Natural Gas COSS

WPSC prepared an embedded COSS and Commission staff prepared two embedded COSS—COSS A and COSS B. The WPSC and Commission staff COSS A models are identified as customer-oriented studies. Commission staff COSS B is a commodity-oriented study. The results differ because the customer-oriented study allocates costs associated with certain plant investments, overheads, and operating expenses to the service rate classes, in part, based on the number of customers in the respective service rate classes. COSS B allocates these costs to the service rate classes, in part, based on the commodity usage of the respective service rate classes.

It is reasonable to rely on all the natural gas COSS presented in this docket as a guide to setting rates. This has been the Commission's policy in the past, and it continues to be the appropriate policy.

Revenue Recovery Adequacy of Service Class Rates

Overall, the natural gas rates authorized for WPSC in Appendix C of this Final Decision will provide a 7.72 percent rate of return on the average gas net investment rate base. This represents a decrease of 6.45 percent in margin rates and a decrease of 2.61 percent in total natural gas sales revenues. Margin rates exclude natural gas costs. Authorized rates as set forth in Appendix C are based on the cost of supplying natural gas service to the various service rate classes and other rate setting goals. Summaries of the rate impacts on a service rate class are shown in Appendix C.

As shown in Appendix C, the natural gas COSS results in a relatively wide range of changes in the charges to the various service rate classes. To provide for historical continuity in WPSC's rates, the Commission finds it reasonable to authorize service rates that move in the direction of the natural gas COSS results, with intent to make further adjustments in that direction in subsequent rate proceedings. In moving toward the cost-of-service in authorized rates, the Commission tempers the rate increase to the service rate classes that, according to the cost analysis, should receive the largest percentage increases. The resulting revenue difference is recovered through the rates of the remaining service rate classes. The percentage rate increase to any individual customer will not necessarily equal the overall percentage increase to the associated service rate class, but will depend on the specific usage level of the customer. Appendix C shows some typical natural gas bills for residential service, comparing existing rates with new rates, including the cost of natural gas.

Electric and Natural Gas Rates

Revenue Stabilization Mechanism

The authorized electric and natural gas rates reflect the RSM that was set forth in the Energy Efficiency Stipulation approved in the Final Decision issued in docket 6690-UR-119. Pursuant to the Energy Efficiency Stipulation, WPSC agreed to reduce fixed customer charges and recover the loss in revenues, in part, through increases in variable rates; however, a portion totaling $1,680,000 for electric and $420,000 for natural gas is not recoverable in rates. The $1,680,000 for electric and the $420,000 for natural gas reflect the basis reductions not recoverable by an increase in volumetric rates as set forth in the Energy Efficiency Stipulation for the implementation of the RSM.

WPSC and Commission staff agreed to make the following revisions to the RSM tariffs: (1) revise the test year from 2009 to 2011 throughout the existing tariffs; (2) exclude the actual number of customers subscribing to fixed gas sales service and the associated estimated volume sales from the test year amounts; (3) exclude the RSM rates from the volumetric margin rates when determining the annual gross margin over- or under-collection; and (4) add additional tariff pages setting forth the rate adjustments for the applicable service rate classes and have the rates sunset at December 31, 2011. These revisions are reasonable and just, and consistent with the Energy Efficiency Stipulation.

2005 Wisconsin Act 141 Costs

The Act 141 electric costs of $12,550,412 and the Act 141 gas costs of $5,736,716 that are included in the 2011 test year revenue requirements must be allocated differently to "large energy customers" and non-large customers, due to the statutory limitation on how much the large-energy customers pay for these Act 141 costs. In light of the limitations, large-energy customers will provide $3,031,495 fewer electric revenues and $1,515,237 fewer natural gas revenues given their estimated sales volumes and the Act 141 costs included in base rates. The allocated Act 141 costs in base rates are not billed to the large-energy customers. Instead, large-energy customers pay the specific conservation costs that they paid in 2005, adjusted for the increases as set forth in Act 141. The authorized rates as shown in Appendices B and C incorporate these limitations and provide for the cost recovery of the Act 141 limitations associated large-energy customers.

2012 Reopener

WPSC requested to include six items in a rate case reopener proceeding for 2012 as follows:

(1) changes in the cost of fuel, purchased power, opportunity sales, interruptible revenue credits, ATC and Midwest ISO network transmission costs, and other related costs;

(2) amortizations of costs and credits deferred in 2010 and 2011 for SO_2 and nitrous oxides (NO_x) emission allowance costs;

(3) amortization of amounts deferred in 2010 under the electric and natural gas RSMs;

(4) increased Focus on Energy payments;

(5) changes in pensions and benefits costs, including the cost impacts of any new federal health care legislation; and

(6) if the Commission does not replace the "hard" rate adjustment caps in the RSM with an earnings cap, WPSC requests that the limited reopener also include an update for the company's sales forecasts.

The first four items listed above are not contested. Commission staff suggested that changes in pension and benefits costs could be limited to the cost impacts of any new or significantly changed federal health care legislation. Commission staff also noted that the changes in overall pension and benefit costs may be more appropriately addressed in a full rate case proceeding when payroll costs and all other changes in costs are addressed.

WPSC argued that limiting the review of pension and benefits costs to only the impact of federal health care legislation will leave WPSC with very significant cost risks over which it has no control. These include: (1) the pension and benefit discount rate, which could either increase or decrease WPSC's costs in 2012; (2) the pension and benefit growth rate, which could either increase or decrease WPSC's costs in 2012; and (3) the continued "smoothing" of 2008 asset losses, which will likely increase WPSC's costs in 2012.

Finally, in WPSC's arguments to change the RSM fixed caps with an earnings cap, WPSC suggested that either one of two options could be used for 2012. First, WPSC could file a full rate case. Alternatively, the Commission could allow WPSC to include sales on the 2012 list of reopener issues. Commission staff opposed the inclusion of updated sales in a 2012 reopener case on the basis that if sales forecasts are to be updated, then a full rate case should be filed in order to reflect all forecasted costs. CUB supported Commission staff in its opposition to including updated sales forecasts in a limited reopener.

Based on the record in this proceeding, the Commission authorizes a limited 2012 rate reopener proceeding that includes the first four uncontested issues listed above and the impacts of the new or significantly changed federal health care legislation. The Commission does not authorize the inclusion of a new sales forecast in a 2012 rate reopener proceeding.

Effective Date

The test year commences on January 1, 2011. Under Wis. Stat. § 196.40, an order of the Commission shall take effect 20 days after it has been filed and served on the parties to the proceeding, unless the Commission specifies a different effective date in the order. The Commission finds it reasonable for this Final Decision to take effect one day after the date of mailing. Pursuant to Wis. Stat. §§ 196.19 and 196.21, the changes in rates and tariff provisions that are authorized in this Final Decision shall take effect as described below.

The Commission finds it reasonable for the authorized rate increases and all tariff provisions that restrict the terms of service to take effect one day after the date of mailing, provided that these rates and tariff provisions are filed with the Commission and placed in all offices and pay stations of the utility by that date. If these rate increases and tariff provisions are not filed with the Commission and placed in all offices and pay stations by that date, it is reasonable to require that they take effect on the date they are filed with the Commission and placed in all offices and pay stations.

The Commission finds it reasonable for the authorized rate decreases and all tariff provisions that do not restrict the terms of service to take effect one day after the date of mailing. It is also reasonable to require that the utility file these rate decreases and tariff provisions with the Commission and place them in all offices and pay stations of the utility by that date.

Order

1. This Final Decision shall take effect one day after the date of mailing.

2. The authorized rate increases and tariff provisions that restrict the terms of service shall take effect one day after the date of mailing, provided that WPSC files these rates and tariff provisions with the Commission and places them in all of its offices and pay stations by that date. If these rate increases and tariff provisions are not filed with the Commission and placed in all offices and pay stations by that date, they shall take effect on the date they are filed with the Commission and placed in all offices and pay stations.

3. The authorized rate decreases and tariff provisions that expand the terms of service shall take effect one day after the date of mailing. WPSC shall file these rate decreases and tariff provisions with the Commission and place them in all offices and pay stations by that date.

4. WPSC may revise its existing rates and tariff provisions for electric utility service, substituting the rate increases and tariff provisions that restrict the terms of service, as shown in Appendix B. These changes shall be in effect until the Commission issues an order establishing new rates and tariff provisions.

5. By one day after the date of mailing, WPSC shall revise its existing rates and tariff provisions for natural gas utility service, substituting the rate decreases and tariff provisions that

expand the terms of service, as shown in Appendix C. These changes shall be in effect until the Commission issues an order establishing new rates and tariff provisions.

6. WPSC shall prepare bill inserts that appropriately identify the rates authorized in this Final Decision. WPSC shall distribute the inserts to customers no later than the first billing containing these rates. WPSC shall file copies of these inserts with the Commission before it distributes the inserts to customers.

7. WPSC's 2011 test year rate filing EFOR to Weston 4 of 12.3 percent shall be used for purposes of forecasting its 2011 test year fuel costs.

8. 2011 natural gas and spot coal prices shall be based on November 8, 2010, NYMEX futures prices and independent consultant estimated spot coal prices as of that date, as was done in the past.

9. WPSC shall be allowed to recover its attorney's fees associated with the negotiation and recovery of its rail delivery settlement.

10. The fuel costs in Appendix D shall be used for monthly monitoring of WPSC's 2011 fuel costs, pursuant to Wis. Admin. Code ch. PSC 116.

11. WPSC shall use the following ranges to monitor 2011 fuel costs: plus or minus 8 percent monthly; cumulative ranges of plus or minus 8 percent for the first month of the year, plus or minus 5 percent for the second month of the year, and plus or minus 2 percent for the remaining months of the year; and plus or minus 2 percent for the annual range. If the Commission's new fuel rule takes effect in 2011, the monitored fuel costs approved in this proceeding shall be used as WPSC's fuel cost plan. The annual bandwidth shall be plus or minus 2 percent on an annual basis.

12. WPSC shall report monthly to the Commission its actual total system cost of generation and purchased energy less the revenues from opportunity sales of energy and capacity (monitored fuel costs). WPSC shall otherwise comply with the fuel cost determination and monitoring system as set forth in the Findings of Fact.

13. Monitored fuel costs shall continue to be reported, during 2011, under the current definition of monitored fuel costs.

14. For 2011, the Commission will continue to apply the current definition of monitored fuel costs to WPSC.

15. WPSC shall submit a ten-year financial forecast in its next rate case.

16. WPSC shall not pay, without Commission approval, normal dividends greater than 103 percent of the prior year's common dividend. WPSC shall notify the Commission if any special dividend is contemplated. No special dividend that might cause the common equity, on a financial basis, to drop below the projected calendar year average of 50.24 percent or the dollar amount of equity reflected in the test year is permitted without Commission approval.

17. WPSC shall submit, in its next rate case application, detailed information regarding all off-balance sheet obligations for which the financial markets will calculate a debt equivalent. The information shall include, at minimum: (1) the minimum annual lease and PPA obligations; (2) the method of calculation along with the calculated amount of the debt equivalent; and (3) supporting documentation, including all reports, correspondence and any other justification that clearly established S&P's and other major credit rating agencies' determination of the off-balance sheet debt equivalent, to the extent available, and publicly available documentation when S&P and other major credit rating agencies documentation is not available.

18. Should the Commission choose to address the issue of appropriately aligning customer service conservation and load management activities with statewide energy efficiency programs before WPSC's next rate proceeding, WPSC shall work with Commission staff to review its customer service conservation and load management activities to determine if they are still appropriate and propose any changes needed to meet the Commission's policy objectives.

19. If WPSC's customer service conservation activities are modified as a result of any Commission action regarding the appropriate use of customer service conservation and load management dollars, WPSC shall propose modifications to the measures of success consistent with Commission policy and proposed changes in activities.

20. WPSC shall file a final report on the WPSC/Focus on Energy Weston 4 programs by April 1, 2011. The report should include final achievement towards goals and audited expenditures. If it is determined that any of the dollars budgeted for Weston 4 programs in 2008 and 2009 were not spent, WPSC shall work with Commission staff and SEERA to remit these funds.

21. WPSC shall record annual conservation accrual amounts of $17,963,766 for electric utility operations and $7,463,773 for Wisconsin natural gas operations. The level for electric utility operations consists of the conservation budget of $17,436,893, and an escrow adjustment of $526,873, which represents the test year amortization of the projected overspent escrow balance at December 31, 2010, over two years. The level for natural gas operations consists of the conservation budget of $8,994,370 and an escrow adjustment of ($1,530,597), which represents the test year amortization of the projected underspent escrow balance at December 31, 2010, over two

years. WPSC shall continue to record these amounts until the Commission authorizes new demand side management accrual amounts.

22. WPSC's 2011 and 2012 Focus on Energy contributions are to be at the levels specified in the Energy Efficiency Stipulation.

23. WPSC shall develop a three-tier TOU tariff for its small commercial customers for presentation at the time of its next rate proceeding.

24. WPSC is ordered to close the two-tier residential TOU tariff to new customers and to work with existing residential two-tier TOU customers on moving to the residential three-tier TOU offering or the Response Rewards program.

25. WPSC is ordered to create a new comprehensive lighting tariff (Ls-1), eliminate the Residential and Commercial Space Heating and Cooling tariffs (RC-S1 and CG-S1), and cancel the General Water Heating tariff (GW-X).

26. WPSC shall allow customers taking service under its parallel generation tariffs to separately negotiate a renewable credit rate for any renewable energy sold to the utility.

27. WPSC shall increase the capacity limit of its PG-4 tariff to allow net energy billing of customer-owned generation up to 100 kW, sized to the customer's annual load requirement, and limited to the customer's use within the year. Any additional energy shall be credited the standard buyback rate. WPSC shall work with Commission staff to make any necessary modifications to the PG-4 tariff.

28. WPSC shall increase the rate of its voluntary NatureWise tariff to $2.40 per 100 kWh block in order to reflect the full incremental cost of providing renewable energy through the NatureWise program.

29. The Real Time Market Pricing Schedule proposed by WPSC is approved.

30. WPSC shall file tariffs consistent with the Commission's Findings of Fact in this Final Decision.

31. Jurisdiction is retained.

Dated at Madison, Wisconsin, January 13, 2011

By the Commission:

Sandra J. Paske

Sandra J. Paske
Secretary to the Commission

SJP:MEM:CCS:mem:g:\order\pending\6690-UR-120 final.doc

See attached Notice of Rights

PUBLIC SERVICE COMMISSION OF WISCONSIN
610 North Whitney Way
P.O. Box 7854
Madison, Wisconsin 53707-7854

NOTICE OF RIGHTS FOR REHEARING OR JUDICIAL REVIEW, THE TIMES ALLOWED FOR EACH, AND THE IDENTIFICATION OF THE PARTY TO BE NAMED AS RESPONDENT

The following notice is served on you as part of the Commission's written decision. This general notice is for the purpose of ensuring compliance with Wis. Stat. § 227.48(2), and does not constitute a conclusion or admission that any particular party or person is necessarily aggrieved or that any particular decision or order is final or judicially reviewable.

PETITION FOR REHEARING

If this decision is an order following a contested case proceeding as defined in Wis. Stat. § 227.01(3), a person aggrieved by the decision has a right to petition the Commission for rehearing within 20 days of mailing of this decision, as provided in Wis. Stat. § 227.49. The mailing date is shown on the first page. If there is no date on the first page, the date of mailing is shown immediately above the signature line. The petition for rehearing must be filed with the Public Service Commission of Wisconsin and served on the parties. An appeal of this decision may also be taken directly to circuit court through the filing of a petition for judicial review. It is not necessary to first petition for rehearing.

PETITION FOR JUDICIAL REVIEW

A person aggrieved by this decision has a right to petition for judicial review as provided in Wis. Stat. § 227.53. In a contested case, the petition must be filed in circuit court and served upon the Public Service Commission of Wisconsin within 30 days of mailing of this decision if there has been no petition for rehearing. If a timely petition for rehearing has been filed, the petition for judicial review must be filed within 30 days of mailing of the order finally disposing of the petition for rehearing, or within 30 days after the final disposition of the petition for rehearing by operation of law pursuant to Wis. Stat. § 227.49(5), whichever is sooner. If an *untimely* petition for rehearing is filed, the 30-day period to petition for judicial review commences the date the Commission mailed its original decision.[1] The Public Service Commission of Wisconsin must be named as respondent in the petition for judicial review.

If this decision is an order denying rehearing, a person aggrieved who wishes to appeal must seek judicial review rather than rehearing. A second petition for rehearing is not permitted.

Revised: December 17, 2008

[1] *See State v. Currier*, 2006 WI App 12, 288 Wis. 2d 693, 709 N.W.2d 520.

APPENDIX A
(CONTESTED)

In order to comply with Wis. Stat. § 227.47, the following parties who appeared before the agency are considered parties for purposes of review under Wis. Stat. § 227.53.

Public Service Commission of Wisconsin
(Not a party but must be served)
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SCHEDULE 1: AUTHORIZED REVENUES

Rate Class Description	Rate Schedule	Present Revenue	2011 Authorized Revenue	Increase $'s	Increase %
SMALL USE RATE CLASSES					
Residential - Urban	Rg-1	$ 215,384,671	$ 216,685,259	$ 1,300,588	0.60%
Residential - Rural	Rg-2	$ 119,473,702	$ 119,554,810	$ 81,108	0.07%
Residential - Urban Two-Tier Optional Time-Of-Use (TOU)	Rg-3	$ 7,630,700	$ 7,683,778	$ 53,078	0.70%
Residential - Rural Two-Tier Optional TOU	Rg-4	$ 10,410,615	$ 10,526,907	$ 116,292	1.12%
Residential - Urban Three-Tier Optional TOU	Rg-5	$ 256,202	$ 258,197	$ 1,995	0.78%
Residential - Rural Three-Tier Optional TOU	Rg-6	$ 225,519	$ 226,876	$ 1,357	0.60%
Residential Classes		$ 353,381,409	$ 354,935,826	$ 1,554,418	0.44%
Small Urban Commercial & Industrial (C&I), Under 50 KW	Cg-1	$ 74,095,313	$ 75,330,652	$ 1,235,339	1.67%
Small Rural C&I, Under <50 KW	Cg-2	$ 32,419,752	$ 32,884,569	$ 464,817	1.43%
Small Urban C&I Optional TOU	Cg-3	$ 5,332,643	$ 5,415,763	$ 83,121	1.56%
Small Rural C&I Optional TOU	Cg-4	$ 4,024,732	$ 4,090,501	$ 65,769	1.63%
Small CI& Classes		$ 115,872,440	$ 117,721,485	$ 1,849,045	1.60%
Private Street Lighting	Gy-1	$ 1,140,862	$ 1,154,924	$ 14,062	1.23%
Private Area Lighting	Gy-3	$ 3,327,633	$ 3,362,697	$ 35,064	1.05%
Street Lighting	Ms-1	$ 10,915,957	$ 11,034,706	$ 118,748	1.09%
Customer Owned Street Lighting	Ms-3	$ 455,373	$ 462,099	$ 6,726	1.48%
Municipal Ornamental Lighting	Ms-31	$ 10,324	$ 10,397	$ 73	0.71%
Residential Controlled Space Heating	RC-S1	$ 11,302	$ 11,558	$ 256	2.27%
Small C&I Controlled Space Heating	CG-S1	$ 7,562	$ 7,958	$ 396	5.24%
Nature Wise	NAT-R & -C	$ 317,688	$ 609,960	$ 292,273	92.00%
ATS	ATS	$ 64,200	$ 67,620	$ 3,420	5.33%
Parallel Generation	Pg	$ 384	$ 480	$ 96	25.00%
Lighting & Other Class		$ 16,251,285	$ 16,722,399	$ 471,114	2.90%
SMALL USE RATE CLASSES		$ 485,505,134	$ 489,379,710	$ 3,874,576	0.80%
MEDIUM USE CUSTOMERS					
Small C&I, Over 50 kW & Under 100 kW	Cg-5	$ 36,415,476	$ 36,586,917	$ 171,441	0.47%
Medium C&I TOU, Over 100 kW and Under 1,000 KW	Cg-20	$ 203,415,894	$ 204,686,869	$ 1,270,975	0.62%
MEDIUM USE RATE CLASSES		$ 239,831,370	$ 241,273,786	$ 1,442,416	0.60%
INDUSTRIAL USE CUSTOMERS					
Large Commiercial & Industrial, Over 1,000 kW	Cp	$ 222,956,255	$ 223,397,293	$ 441,038	0.20%
INDUSTRIAL USE RATE CLASSES		$ 222,956,255	$ 223,397,293	$ 441,038	0.20%
ALL RATE CLASSES		$ 948,292,758	$ 954,050,789	$ 5,758,030	0.61%

SCHEDULE 2: AUTHORIZED RATES

Rate Schedule Tariff Charge	Current Rates	Authorized 2011 Rates*	Authorized 2012 Rates		Daily Charge	
Rg-1 URBAN RESIDENTIAL						
Customer Charge						
Single PH	$5.70	$5.70	$5.70	$/Month	$0.1874	$/Day
Three PH	$9.70	$9.70	$9.70	$/Month	$0.3189	$/Day
Energy Charges	$0.11983	$0.12209	$0.11940	$/kWh		
RSM Surcharge - Applies to all kWh*		$0.00269	$0.00000	$/kWh		
2010 Fuel Refund Credit - Applies to all kWh**		($0.00148)	$0.00000	$/kWh		
Lg Cust Act 141 Capped 2005$		$0.00096	$0.00096	$/kWh		
Lg Cust Credits to comply w/Act 141		($0.00183)	($0.00183)	$/kWh		
Rg-2 RURAL RESIDENTIAL						
Customer Charge						
Single PH	$7.00	$7.00	$7.00	$/Month	$0.2301	$/Day
Three PH	$11.00	$11.00	$11.00	$/Month	$0.3616	$/Day
Energy Charges	$0.12052	$0.12209	$0.11940	$/kWh		
RSM Surcharge - Applies to all kWh*		$0.00269	$0.00000	$/kWh		
2010 Fuel Refund Credit - Applies to all kWh**		($0.00148)	$0.00000	$/kWh		
Lg Cust Act 141 Capped 2005$		$0.00113	$0.00113	$/kWh		
Lg Cust Credits to comply w/Act 141		($0.00183)	($0.00183)	$/kWh		
Rg-3 OTOU URBAN RESIDENTIAL OPTIONAL TIME-OF-USE (Closed To New Customers)						
Customer Charge						
Single PH - Urban	$5.70	$5.70	$5.70	$/Month	$0.1874	$/Day
Three PH - Urban	$9.70	$9.70	$9.70	$/Month	$0.3189	$/Day
Water Heater						
Control Charge	$4.80	$4.80	$4.80	$/Month	$0.1578	$/Day
Control Charge - Seasonal	$9.60	$9.60	$9.60	$/Month	$0.3156	$/Day
Energy Charges						
On Peak - Urban	$0.21867	$0.20887	$0.20618	$/kWh		
Off Peak - Urban	$0.06310	$0.06990	$0.06721	$/kWh		
RSM Surcharge - Applies to all kWh*		$0.00269	$0.00000	$/kWh		
2010 Fuel Refund Credit - Applies to all kWh**		($0.00148)	$0.00000	$/kWh		
Lg Cust Act 141 Capped 2005$		$0.00013	$0.00013	$/kWh		
Lg Cust Credits to comply w/Act 141		($0.00183)	($0.00183)	$/kWh		
Rg-4 OTOU RURAL RESIDENTIAL OPTIONAL TIME-OF-USE (Closed To New Customers)						
Customer Charge						
Single PH - Rural	$7.00	$7.00	$7.00	$/Month	$0.2301	$/Day
Three PH - Rural	$11.00	$11.00	$11.00	$/Month	$0.3616	$/Day
Water Heater						
Control Charge	$4.80	$4.80	$4.80	$/Month	$0.1578	$/Day
Control Charge - Seasonal	$9.60	$9.60	$9.60	$/Month	$0.3156	$/Day
Energy Charges						
On Peak - Rural	$0.21867	$0.20887	$0.20618	$/kWh		
Off Peak - Rural	$0.06310	$0.06990	$0.06721	$/kWh		
RSM Surcharge - Applies to all kWh*		$0.00269	$0.00000	$/kWh		
2010 Fuel Refund Credit - Applies to all kWh**		($0.00148)	$0.00000	$/kWh		
Lg Cust Act 141 Capped 2005$		$0.00013	$0.00013	$/kWh		
Lg Cust Credits to comply w/Act 141		($0.00183)	($0.00183)	$/kWh		

*/ Rate Stabilization Mechanism Surcharge included in 2011 Rates and removed from 2012 Rates
**/ 2010 Fuel refund expires at end of 2011. No fuel refund identified for 2012.

SCHEDULE 2: AUTHORIZED RATES (Continued)

Rate Schedule Tariff Charge	Current Rates	Authorized 2011 Rates*	Authorized 2012 Rates		Daily Charge	
Rg-5 OTOU URBAN THREE-TIER RESIDENTIAL OPTIONAL TIME-OF-USE						
Customer Charge						
Single PH - Urban	$5.70	$5.70	$5.70	$/Month	$0.1874	$/Day
Three PH - Urban	$9.70	$9.70	$9.70	$/Month	$0.3189	$/Day
Water Heater						
Control Charge	$4.80	$4.80	$4.80	$/Month	$0.1578	$/Day
Control Charge - Seasonal	$9.60	$9.60	$9.60	$/Month	$0.3156	$/Day
Energy Charges						
On Peak - Urban	$0.26022	$0.27624	$0.27355	$/kWh		
Shoulder - Urban	$0.11983	$0.12209	$0.11940	$/kWh		
Off Peak - Urban	$0.07230	$0.06990	$0.06721	$/kWh		
RSM Surcharge - Applies to all kWh*		$0.00269	$0.00000	$/kWh		
2010 Fuel Refund Credit - Applies to all kWh**		($0.00148)	$0.00000	$/kWh		
Lg Cust Act 141 Capped 2005$		$0.00096	$0.00096	$/kWh		
Lg Cust Credits to comply w/Act 141		($0.00183)	($0.00183)	$/kWh		
Rg-6 OTOU RURAL THREE-TIER RESIDENTIAL OPTIONAL TIME-OF-USE						
Customer Charge						
Single PH - Urban	$7.00	$7.00	$7.00	$/Month	$0.2301	$/Day
Three PH - Urban	$11.00	$11.00	$11.00	$/Month	$0.3616	$/Day
Water Heater						
Control Charge	$4.80	$4.80	$4.80	$/Month	$0.1578	$/Day
Control Charge - Seasonal	$9.60	$9.60	$9.60	$/Month	$0.3156	$/Day
Energy Charges						
On Peak - Urban	$0.26022	$0.27624	$0.27355	$/kWh		
Shoulder - Urban	$0.11983	$0.12209	$0.11940	$/kWh		
Off Peak - Urban	$0.07230	$0.06990	$0.06721	$/kWh		
RSM Surcharge - Applies to all kWh*		$0.00269	$0.00000	$/kWh		
2010 Fuel Refund Credit - Applies to all kWh**		($0.00148)	$0.00000	$/kWh		
Lg Cust Act 141 Capped 2005$		$0.00096	$0.00096	$/kWh		
Lg Cust Credits to comply w/Act 141		($0.00183)	($0.00183)	$/kWh		
Rg-DC, Residential Direct Control Rider						
AC Cycling	$0.00	$0.00	$0.00	$/Month		
AC 100% Load Shed/Cycling	$8.00	$8.00	$8.00	$/Month		
WH 100% Load Shed/Cycling	$2.00	$2.00	$2.00	$/Month		
Rg-RR, Residential Response Rewards						
All Customer Charges		Same as Rg Classes				
Energy Charges						
On Peak	$0.21853	$0.22607	$0.22338	$/kWh		
Off-Peak	$0.07230	$0.06990	$0.06721	$/kWh		
Critical Peak	$0.45000	$1.00000	$1.00000	$/kWh		
RSM Surcharge - Applies to all kWh*		$0.00269	$0.00000	$/kWh		
2010 Fuel Refund Credit - Applies to all kWh**		($0.00148)	$0.00000	$/kWh		

*/ Rate Stabilization Mechanism Surcharge includes in 2011 Rates and removed from 2012 Rates
**/ 2010 Fuel refund expires at end of 2011. No fuel refund identified for 2012.

SCHEDULE 2: AUTHORIZED RATES (Continued)

Rate Schedule Tariff Charge	Current Rates	Authorized 2011 Rates*	Authorized 2012 Rates		Daily Charge	
Cg-1 URBAN SMALL C&I (<50 KW)						
Customer Charge						
Single Phase	$7.25	$7.25	$7.25	$/Month	$0.2384	$/Day
Three Phase	$10.25	$10.25	$10.25	$/Month	$0.3370	$/Day
Energy Charge	$0.11855	$0.12209	$0.11940	$/kWh		
RSM Surcharge - Applies to all kWh*		$0.00269	$0.00000	$/kWh		
2010 Fuel Refund Credit - Applies to all kWh**		($0.00148)	$0.00000	$/kWh		
Lg Cust Act 141 Capped 2005$		$0.00104	$0.00104	$/kWh		
Lg Cust Credits to comply w/Act 141		($0.00139)	($0.00139)	$/kWh		
Cg-1-RR, Small C&I Urban Response Rewards						
All Customer Charges		Same as Cg-1 Class				
Energy Charges						
On Peak	$0.21853	$0.22607	$0.22338	$/kWh		
Off-Peak	$0.07230	$0.06990	$0.06721	$/kWh		
Critical Peak	$0.45000	$1.00000	$1.00000	$/kWh		
RSM Surcharge - Applies to all kWh*		$0.00269	$0.00000	$/kWh		
2010 Fuel Refund Credit - Applies to all kWh**		($0.00148)	$0.00000	$/kWh		
Cg-2 RURAL SMALL C&I (<50 KW)						
Customer Charge						
Single Phase	$8.50	$8.50	$8.50	$/Month	$0.2795	$/Day
Three Phase	$11.50	$11.50	$11.50	$/Month	$0.3781	$/Day
Energy Charge	$0.11882	$0.12209	$0.11940	$/kWh		
RSM Surcharge - Applies to all kWh*		$0.00269	$0.00000	$/kWh		
2010 Fuel Refund Credit - Applies to all kWh**		($0.00148)	$0.00000	$/kWh		
Lg Cust Act 141 Capped 2005$		$0.00045	$0.00045	$/kWh		
Lg Cust Credits to comply w/Act 141		($0.00139)	($0.00139)	$/kWh		
Cg-2-RR, Small C&I Rural Response Rewards						
All Customer Charges		Same as Cg-2 Class				
Energy Charges						
On Peak	$0.21853	$0.22607	$0.22338	$/kWh		
Off-Peak	$0.07230	$0.06990	$0.06721	$/kWh		
Critical Peak	$0.45000	$1.00000	$1.00000	$/kWh		
RSM Surcharge - Applies to all kWh*		$0.00269	$0.00000	$/kWh		
2010 Fuel Refund Credit - Applies to all kWh**		($0.00148)	$0.00000	$/kWh		
Cg-5 SMALL C&I (50 < KW > 100)						
Customer Charge						
Single Phase	$15.00	$15.00	$15.00	$/Month	$0.4932	$/Day
Three Phase	$19.00	$19.00	$19.00	$/Month	$0.6247	$/Day
Energy Charges	$0.10275	$0.10472	$0.10203	$/kWh		
RSM Surcharge - Applies to all kWh*		$0.00269	$0.00000	$/kWh		
2010 Fuel Refund Credit - Applies to all kWh**		($0.00148)	$0.00000	$/kWh		
Lg Cust Act 141 Capped 2005$		$0.00062	$0.00062	$/kWh		
Lg Cust Credits to comply w/Act 141		($0.00139)	($0.00139)	$/kWh		

*/ Rate Stabilization Mechanism Surcharge included in 2011 Rates and removed from 2012 Rates
**/ 2010 Fuel refund expires at end of 2011. No fuel refund identified for 2012.

SCHEDULE 2: AUTHORIZED RATES (Continued)

Rate Schedule Tariff Charge	Current Rates	Authorized 2011 Rates*	Authorized 2012 Rates		Daily Charge	
Cg-5-RR, Small C&I Response Rewards						
All Customer Charges		Same as Cg-5 Class				
Energy Charges						
On Peak	$0.15567	$0.16300	$0.16031	$/kWh		
Off-Peak	$0.06254	$0.06548	$0.06279	$/kWh		
Critical Peak	$0.45000	$1.00000	$1.00000	$/kWh		
RSM Surcharge - Applies to all kWh*		$0.00269	$0.00000	$/kWh		
2010 Fuel Refund Credit - Applies to all kWh**		($0.00148)	$0.00000	$/kWh		
Cg-3 URBAN OTOU C&I OPTIONAL TOU						
Customer Charge						
Single PH - Urban	$7.25	$7.25	$7.25	$/Month	$0.2384	$/Day
Three PH - Urban	$10.25	$10.25	$10.25	$/Month	$0.3370	$/Day
Water Heater Control Charge	$4.80	$4.80	$4.80	$/Month	$0.1578	$/Day
Water Heater Control Charge-Seasonal	$9.60	$9.60	$9.60	$/Month	$0.3156	$/Day
On Peak Energy Charge	$0.21788	$0.20887	$0.20618	$/kWh		
Off Peak Energy Charge	$0.06227	$0.06990	$0.06721	$/kWh		
RSM Surcharge - Applies to all kWh*		$0.00269	$0.00000	$/kWh		
2010 Fuel Refund Credit - Applies to all kWh**		($0.00148)	$0.00000	$/kWh		
Lg Cust Act 141 Capped 2005$		$0.00060	$0.00060	$/kWh		
Lg Cust Credits to comply w/Act 141		($0.00139)	($0.00139)	$/kWh		
Cg-4 RURAL OTOU C&I OPTIONAL TOU						
Customer Charge						
Single PH - Rural	$8.50	$8.50	$8.50	$/Month	$0.2795	$/Day
Three PH - Rural	$11.50	$11.50	$11.50	$/Month	$0.3781	$/Day
Water Heater Control Charge	$4.80	$4.80	$4.80	$/Month	$0.1578	$/Day
Water Heater Control Charge-Seasonal	$9.60	$9.60	$9.60	$/Month	$0.3156	$/Day
On Peak Energy Charge	$0.21788	$0.20887	$0.20618	$/kWh		
Off Peak Energy Charge	$0.06227	$0.06990	$0.06721	$/kWh		
RSM Surcharge - Applies to all kWh*		$0.00269	$0.00000	$/kWh		
2010 Fuel Refund Credit - Applies to all kWh**		($0.00148)	$0.00000	$/kWh		
Lg Cust Act 141 Capped 2005$		$0.00024	$0.00024	$/kWh		
Lg Cust Credits to comply w/Act 141		($0.00139)	($0.00139)	$/kWh		
Cg-20-TOU C&I (100-1000 KW) COMMERCIAL & INDUSTRIAL TIME-OF-USE						
Customer Charge						
Secondary	$30.50	$30.50	$30.50	$/Month	$1.0027	$/Day
Primary	$58.30	$58.30	$58.30	$/Month	$1.9167	$/Day
Customer Demand Charge	$1.407	$1.468	$1.468	$/kW		
Standby	$1.840	$1.956	$1.956	$/kW		
System Demand Charge						
Summer	$10.670	$10.865	$10.865	$/kW		
Winter	$7.312	$7.446	$7.446	$/kW		
On-Peak Energy Charge	$0.07220	$0.07380	$0.07237	$/kWh		
Off-Peak Energy Charge	$0.04338	$0.04460	$0.04317	$/kWh		
Energy Limiter	$0.17082	$0.17342	$0.17199	$/kWh		
RSM Surcharge - Applies to all kWh*		$0.00143	$0.00000	$/kWh		
2010 Fuel Refund Credit - Applies to all kWh**		($0.00148)	$0.00000	$/kWh		
Lg Cust Act 141 Capped 2005$		$0.00034	$0.00034	$/kWh		
Lg Cust Credits to comply w/Act 141		($0.00139)	($0.00139)	$/kWh		

*/ Rate Stabilization Mechanism Surcharge included in 2011 Rates and removed from 2012 Rates

**/ 2010 Fuel refund expires at end of 2011. No fuel refund identified for 2012.

SCHEDULE 2: AUTHORIZED RATES (Continued)

Rate Schedule Tariff Charge	Current Rates	Authorized 2011 Rates*	Authorized 2012 Rates		Daily Charge	
Cg-20-RR, TOU C&I Response Rewards						
All Customer Charges		Same as Cg-20 Class				
System Demand Charges						
Summer	$8.003	$8.149	$8.149	$/kW		
Winter	$5.484	$5.585	$5.585	$/kW		
Energy Charges						
On Peak	$0.05357	$0.04788	$0.04645	$/kWh		
Off-Peak	$0.03900	$0.04000	$0.03857	$/kWh		
Critical Peak	$0.35000	$0.40000	$0.40000	$/kWh		
RSM Surcharge - Applies to all kWh*		$0.00143	$0.00000	$/kWh		
2010 Fuel Refund Credit - Applies to all kWh**		($0.00148)	$0.00000	$/kWh		
Cg-DC, Commercial Direct Control Rider						
AC Cycling	$4.00	$4.00	$4.00	$/Month		
AC 100% Load Shed/Cycling	$9.00	$9.00	$9.00	$/Month		
WH 100% Load Shed/Cycling	$2.00	$2.00	$2.00	$/Month		
Contracted Direct Load Control						
Switch Charge - Summer - Ground Mount	$12.00	$12.00	$12.00	$/Month		
Switch Charge - Summer - Ground Mount	$18.00	$18.00	$18.00	$/Month		
Switch Charge - Summer - Ground Mount	$28.00	$28.00	$28.00	$/Month		
Switch Charge - Summer - Ground Mount	$6.00	$6.00	$6.00	$/Month		
Switch Charge - Summer - Ground Mount	$9.33	$9.33	$9.33	$/Month		
Summer 50% Cycling	($6.50)	($6.50)	($6.50)	$/Month		
Summer 100% Load Shed/Cycling	($6.50)	($6.50)	($6.50)	$/Month		
Year Round !00% Load Shed/Cycling	($4.35)	($4.35)	($4.35)	$/Month		
Cp Large C&I (>1000 KW) INDUSTRIAL TIME-OF USE						
Customer Charge						
Secondary	$322.000	$341.000	$341.00	$/Month	$11.2110	$/Day
Primary	$375.000	$398.000	$398.00	$/Month	$13.0849	$/Day
Transmission	$858.000	$909.000	$909.00	$/Month	$29.8849	$/Day
Distribution Demand Charge (Secondary)	$1.957	$2.080	$2.080	$/kW		
Distribution Demand Charge (Primary)	$1.722	$1.830	$1.830	$/kW		
Substation - Transformer Capacity (Transmission)	$0.583	$0.583	$0.583	$/kW		
Standby	$3.500	$3.500	$3.500	$/kW		
System Demand Charges						
Peak - Summer (Secondary)	$10.758	$11.062	$11.062	$/kW		
Peak - Summer (Pirmary)	$10.484	$10.773	$10.773	$/kW		
Peak - Summer (Transmission)	$10.295	$10.606	$10.606	$/kW		
Peak - Winter (Secondary)	$5.918	$6.085	$6.085	$/kW		
Peak - Winter (Primary)	$5.768	$5.926	$5.926	$/kW		
Peak - Winter (Transmission)	$5.663	$5.834	$5.834	$/kW		

*/ Rate Stabilization Mechanism Surcharge included in 2011 Rates and removed from 2012 Rates
**/ 2010 Fuel refund expires at end of 2011. No fuel refund identified for 2012.

SCHEDULE 2: AUTHORIZED RATES (Continued)

Rate Schedule / Tariff Charge	Current Rates	Authorized 2011 Rates*	Authorized 2012 Rates		Daily Charge
Cp Large C&I (>1000 KW) INDUSTRIAL TIME-OF USE (Continued)					
Intermediate - Summer (Secondary)	$8.069	$8.297	8.297	$/kW	
Intermediate - Summer (Primary)	$7.863	$8.080	8.080	$/kW	
Intermediate - Summer (Transmission)	$7.721	$7.955	7.955	$/kW	
Intermediate - Winter (Secondary)	$4.439	$4.564	4.564	$/kW	
Intermediate - Winter (Primary)	$4.326	$4.445	4.445	$/kW	
Intermediate - Winter (Transmission)	$4.247	$4.376	4.376	$/kW	
Variable Interruptible - Summer (Secondary)	$4.457	$4.761	$4.761	$/kW	
Credit (Secondary)	-$6.301	-$6.301	-$6.301	$/kW	
Variable Interruptible - Summer (Primary)	$4.183	$4.472	$4.472	$/kW	
Credit (Primary)	-$6.301	-$6.301	-$6.301	$/kW	
Variable Interruptible - Summer (Transmission)	$3.994	$4.305	$4.305	$/kW	
Credit (Transmission)	-$6.301	-$6.301	-$6.301	$/kW	
Variable Interruptible - Winter (Secondary)	$2.767	$2.934	$2.934	$/kW	
Credit (Secondary)	-$3.151	-$3.151	-$3.151	$/kW	
Variable Interruptible - Winter (Primary)	$2.617	$2.775	$2.775	$/kW	
Credit (Primary)	-$3.151	-$3.151	-$3.151	$/kW	
Variable Interruptible - Winter (Transmission)	$2.512	$2.683	$2.683	$/kW	
Credit (Transmission)	-$3.151	-$3.151	-$3.151	$/kW	
Energy Charges					
On-Peak Energy Charge (Secondary)	$0.06233	$0.06206	$0.06206	$/kWh	
On-Peak Energy Charge (Primary)	$0.06068	$0.06080	$0.06080	$/kWh	
On-Peak Energy Charge (Transmission)	$0.05985	$0.06006	$0.06006	$/kWh	
Off-Peak Energy Charge (Secondary)	$0.03344	$0.03514	$0.03514	$/kWh	
Off-Peak Energy Charge (Primary)	$0.03255	$0.03442	$0.03442	$/kWh	
Off-Peak Energy Charge (Transmission)	$0.03211	$0.03400	$0.03400	$/kWh	
RSM Surcharge - Applies to all kWh*		$0.00000	$0.00000	$/kWh	
2010 Fuel Refund Credit - Applies to all kWh**		($0.00148)	$0.00000	$/kWh	
Lg Cust Act 141 Capped 2005$		$0.00033	$0.00033	$/kWh	
Lg Cust Credits to comply w/Act 141		($0.00139)	($0.00139)	$/kWh	
Cp-RR Large C&I Response Rewards					
All Customer Charges		Same as Cp Class			
System Demand Charges					
Peak - Summer (Secondary)	$8.069	$8.297	$8.297	$/kW	
Peak - Summer (Pimary)	$7.863	$8.080	$8.080	$/kW	
Peak - Summer (Transmission)	$7.721	$7.955	$7.955	$/kW	
Peak - Winter (Secondary)	$4.439	$4.564	$4.564	$/kW	
Peak - Winter (Primary)	$4.326	$4.445	$4.445	$/kW	
Peak - Winter (Transmission)	$4.247	$4.376	$4.376	$/kW	
Intermediate - Summer (Secondary)	$6.051	$6.222	$6.222	$/kW	
Intermediate - Summer (Primary)	$5.897	$6.060	$6.060	$/kW	
Intermediate - Summer (Transmission)	$5.791	$5.966	$5.966	$/kW	
Intermediate - Winter (Secondary)	$3.329	$3.423	$3.423	$/kW	
Intermediate - Winter (Primary)	$3.245	$3.333	$3.333	$/kW	
Intermediate - Winter (Transmission)	$3.185	$3.282	$3.282	$/kW	
Energy Charges					
Critical (Secondary)	$0.35000	$0.40000	$0.40000	$/kWh	
Critical (Primary)	$0.34073	$0.38941	$0.38941	$/kWh	
Critical (Transmission)	$0.33069	$0.38411	$0.38411	$/kWh	

*/ Rate Stabilization Mechanism Surcharge included in 2011 Rates and removed from 2012 Rates

**/ 2010 Fuel refund expires at end of 2011. No fuel refund identified for 2012.

SCHEDULE 2: AUTHORIZED RATES (Continued)

Rate Schedule / Tariff Charge	Current Rates	Authorized 2011 Rates*	Authorized 2012 Rates		Daily Charge
Cp-RR Large C&I Response Rewards (Continued)					
On-Peak Energy Charge (Secondary)	$0.04863	$0.04488	$0.04488	$/kWh	
On-Peak Energy Charge (Primary)	$0.04734	$0.04369	$0.04369	$/kWh	
On-Peak Energy Charge (Transmission)	$0.04670	$0.04310	$0.04310	$/kWh	
Off-Peak Energy Charge (Secondary)	$0.03009	$0.03187	$0.03187	$/kWh	
Off-Peak Energy Charge (Primary)	$0.02930	$0.03102	$0.03102	$/kWh	
Off-Peak Energy Charge (Transmission)	$0.02890	$0.03060	$0.03060	$/kWh	
RSM Surcharge - Applies to all kWh*		$0.00000	$0.00000	$/kWh	
2010 Fuel Refund Credit - Applies to all kWh**		($0.00148)	$0.00000	$/kWh	
Cp-ND Large C&I Next Day Pricing Option					
System Demand Charges		Same as Cp Class			
Energy Charges					
Off-Peak Charges		Same as Cp Class			
On-Peak Charges					
Critical Day					
Secondary	$0.13689	$0.14135	$0.14135	$/kWh	
Primary	$0.13326	$0.13848	$0.13848	$/kWh	
Transmission	$0.13145	$0.13680	$0.13680	$/kWh	
Peak Day					
Secondary	$0.08338	$0.07809	$0.07809	$/kWh	
Primary	$0.08116	$0.07651	$0.07651	$/kWh	
Transmission	$0.08006	$0.07558	$0.07558	$/kWh	
Mid-Economy Day					
Secondary	$0.05181	$0.05348	$0.05348	$/kWh	
Primary	$0.05044	$0.05239	$0.05239	$/kWh	
Transmission	$0.04975	$0.05175	$0.05175	$/kWh	
Economy Day					
Secondary	$0.03200	$0.03830	$0.03830	$/kWh	
Primary	$0.03115	$0.03752	$0.03752	$/kWh	
Transmission	$0.03073	$0.03706	$0.03706	$/kWh	
RSM Surcharge - Applies to all kWh*		$0.00000	$0.00000	$/kWh	
2010 Fuel Refund Credit - Applies to all kWh**		($0.00148)	$0.00000	$/kWh	
Gy-1 Private Street Lighting					
Mercury Vapor					
7000 Lumens (175 W)	$17.39	Removed with LS-1 Proposal		$/Unit/Month	
11,000 Lumens (150W)	$19.72	Removed with LS-1 Proposal		$/Unit/Month	
20,000 Lumens	$24.35	Removed with LS-1 Proposal		$/Unit/Month	
Sodium Vapor					
9,000 Lumens (100W)	$17.39	$17.57	$17.57	$/Unit/Month	
14,000 Lumens (150W)	$19.72	$20.08	$20.08	$/Unit/Month	
27,000 Lumens (250 W)	$24.35	$24.79	$24.79	$/Unit/Month	
45,000 Lumens (400W)	$33.71	$33.28	$33.28	$/Unit/Month	
Wood Poles	$4.95	$5.08	$5.08	$/Unit/Month	
Fiberglass Poles 25' / 20'	$8.07	$8.47	$8.47	$/Unit/Month	
Fiberglass Poles 30' / 25'	$10.94	$10.94	$10.94	$/Unit/Month	
Fiberglass Poles 35' / 30'	$13.70	$13.70	$13.70	$/Unit/Month	
Fiberglass Poles 40' / 35'	$22.79	$22.79	$22.79	$/Unit/Month	
Spans	$2.14	$2.24	$2.24	$/Unit/Month	
Excess Footage - Mast Arm	$0.23	$0.23	$0.23	$/Unit/Month	

*/ Rate Stabilization Mechanism Surcharge included in 2011 Rates and removed from 2012 Rates
**/ 2010 Fuel refund expires at end of 2011. No fuel refund identified for 2012.

SCHEDULE 2: AUTHORIZED RATES (Continued)

Rate Schedule / Tariff Charge	Current Rates	Authorized 2011 Rates*	Authorized 2012 Rates		Daily Charge
Gy-1 Private Street Lighting (Continued)					
Discounts					
Mercury Vapor					
7,000 Lumens (175W)	-$2.28	Removed with LS-1 Proposal		$/Unit/Month	
11,000 Lumens (250W)	-$3.16	Removed with LS-1 Proposal		$/Unit/Month	
20,000 Lumens (400W)	-$4.98	Removed with LS-1 Proposal		$/Unit/Month	
Sodium Vapor					
9,000 Lumens (100W)	-$1.26	Removed with LS-1 Proposal		$/Unit/Month	
14,000 Lumens (150W)	-$1.87	Removed with LS-1 Proposal		$/Unit/Month	
27,000 Lumens (250 W)	-$3.20	Removed with LS-1 Proposal		$/Unit/Month	
45,000 Lumens (400W)	-$5.09	Removed with LS-1 Proposal		$/Unit/Month	
Fuel Refund Credit - Applies to all kWh		($0.00148)	$0.00000	$/kWh	
Lg Cust Act 141 Capped 2005$		$0.00130	$0.00130	$/kWh	
Lg Cust Credits to comply w/Act 141		($0.00139)	($0.00139)	$/kWh	
Gy-3 Private Area Lighting					
Mercury Vapor					
7000 Lumens (100W) Area	$12.53	Removed with LS-1 Proposal		$/Unit/Month	
20,000 Lumens (150W) Area	$22.65	Removed with LS-1 Proposal		$/Unit/Month	
20,000 Lumens (150W) Directional	$25.76	Removed with LS-1 Proposal		$/Unit/Month	
57,000 Lumens (400W) Directional	$50.99	Removed with LS-1 Proposal		$/Unit/Month	
Sodium Vapor					
9,000 Lumens (100W) Area	$12.53	$12.98	$12.98	$/Unit/Month	
14,000 Lumens (150W) Area	$15.53	$15.84	$15.84	$/Unit/Month	
27,000 Lumens (250 W) Directional	$30.05	$30.05	$30.05	$/Unit/Month	
45,000 Lumens (400W) Directional	$36.78	$36.78	$36.78	$/Unit/Month	
Metal Halide					
36,000 Lumens (400W)	$36.52	$36.52	$36.52	$/Unit/Month	
110,000 Lumens (1000 W)	$55.50	$55.50	$55.50	$/Unit/Month	
Wood Poles	$4.95	$5.08	$5.08	$/Unit/Month	
Fiberglass Poles 25' / 20'	$8.07	$8.47	$8.47	$/Unit/Month	
Fiberglass Poles 30' / 25'	$10.94	$10.94	$10.94	$/Unit/Month	
Fiberglass Poles 35' / 30'	$13.70	$13.70	$13.70	$/Unit/Month	
Fiberglass Poles 40' / 35'	$22.79	$22.79	$22.79	$/Unit/Month	
Spans	$2.14	$2.24	$2.24	$/Unit/Month	
Discounts					
Mercury Vapor					
7,000 Lumens (100W)	-$2.28	Removed with LS-1 Proposal		$/Unit/Month	
20,000 Lumens (400W)	-$4.98	Removed with LS-1 Proposal		$/Unit/Month	
Sodium Vapor					
9,000 Lumens (100W)	-$1.33	Removed with LS-1 Proposal		$/Unit/Month	
14,000 Lumens (150W)	-$1.87	Removed with LS-1 Proposal		$/Unit/Month	
27,000 Lumens (250W)	-$3.20	Removed with LS-1 Proposal		$/Unit/Month	
45,000 Lumens (400W)	-$5.09	Removed with LS-1 Proposal		$/Unit/Month	
Metal Halide					
36,000 Lumens (400W)	-$4.92	Removed with LS-1 Proposal		$/Unit/Month	
110,000 Lumens (1000W)	-$10.35	Removed with LS-1 Proposal		$/Unit/Month	
Fuel Refund Credit - Applies to all kWh		($0.00148)	$0.00000	$/kWh	
Lg Cust Act 141 Capped 2005$		$0.00102	$0.00102	$/kWh	
Lg Cust Credits to comply w/Act 141		($0.00139)	($0.00139)	$/kWh	

*/ Rate Stabilization Mechanism Surcharge included in 2011 Rates and removed from 2012 Rates
**/ 2010 Fuel refund expires at end of 2011. No fuel refund identified for 2012.

SCHEDULE 2: AUTHORIZED RATES (Continued)

Rate Schedule Tariff Charge	Current Rates	Authorized 2011 Rates*	Authorized 2012 Rates		Daily Charge
Ms-1 Street Lighting					
Mercury Vapor					
7000 Lumens (100W)	$17.39	Removed with LS-1 Proposal		$/Unit/Month	
11,000 Lumens (150W)	$19.72	Removed with LS-1 Proposal		$/Unit/Month	
20,000 Lumens (250W)	$24.35	Removed with LS-1 Proposal		$/Unit/Month	
Sodium Vapor					
9,000 Lumens (100W)	$17.39	$17.57	$17.57	$/Unit/Month	
14,000 Lumens (150W)	$19.72	$20.08	$20.08	$/Unit/Month	
27,000 Lumens (250 W)	$24.35	$24.79	$24.79	$/Unit/Month	
45,000 Lumens (400W)	$33.71	$33.28	$33.28	$/Unit/Month	
Metal Halide				$/Unit/Month	
36,000 Lumens (400 W)	$33.71	$33.28	$33.28	$/Unit/Month	
Fixtures					
Acorn / New Haven (9,000 Lumen)	$2.25	Removed with LS-1 Proposal		$/Unit/Month	
Dorchester (9,000 Lumen)	$4.22	Removed with LS-1 Proposal		$/Unit/Month	
Traditionaire (9,000 Lumen)	$1.50	Removed with LS-1 Proposal		$/Unit/Month	
Traditionaire (14,000 Lumen)	$1.83	Removed with LS-1 Proposal		$/Unit/Month	
Shoe Box (14,000 Lumen)	$2.99	Removed with LS-1 Proposal		$/Unit/Month	
Shoe Box (27,000 Lumen)	$3.72	Removed with LS-1 Proposal		$/Unit/Month	
Shoe Box (45,000 Lumen)	$5.86	Removed with LS-1 Proposal		$/Unit/Month	
Westminster (9,000 Lumen)	$2.70	Removed with LS-1 Proposal		$/Unit/Month	
Discounts					
Mercury Vapor					
7,000 Lumens (175W)	-$2.28	Removed with LS-1 Proposal		$/Unit/Month	
11,000 Lumens (250W)	-$3.16	Removed with LS-1 Proposal		$/Unit/Month	
20,000 Lumens (400W)	-$4.98	Removed with LS-1 Proposal		$/Unit/Month	
38,000 Lumens (700W)	-$8.43	Removed with LS-1 Proposal		$/Unit/Month	
57,000 Lumens (1000W)	-$11.91	Removed with LS-1 Proposal		$/Unit/Month	
Sodium Vapor					
9,000 Lumens (100W)	-$1.33	Removed with LS-1 Proposal		$/Unit/Month	
14,000 Lumens (150W)	-$1.98	Removed with LS-1 Proposal		$/Unit/Month	
27,000 Lumens (250 W)	-$3.40	Removed with LS-1 Proposal		$/Unit/Month	
45,000 Lumens (400W)	-$5.09	Removed with LS-1 Proposal		$/Unit/Month	
Fuel Refund Credit - Applies to all kWh		($0.00148)	$0.00000	$/kWh	
Lg Cust Act 141 Capped 2005$		$0.00096	$0.00096	$/kWh	
Lg Cust Credits to comply w/Act 141		($0.00139)	($0.00139)	$/kWh	

*/ Rate Stabilization Mechanism Surcharge included in 2011 Rates and removed from 2012 Rates
**/ 2010 Fuel refund expires at end of 2011. No fuel refund identified for 2012.

SCHEDULE 2: AUTHORIZED RATES (Continued)

Rate Schedule Tariff Charge	Current Rates	Authorized 2011 Rates*	Authorized 2012 Rates		Daily Charge
Ms-3 Customer Owned Street Lighting					
Mercury Vapor					
7,000 Lumens (100W)	$14.05	Removed with LS-1 Proposal		$/Unit/Month	
11,000 Lumens (150W)	$16.93	Removed with LS-1 Proposal		$/Unit/Month	
20,000 Lumens (250W)	$21.65	Removed with LS-1 Proposal		$/Unit/Month	
38,000 Lumens (400 W)	$28.40	Removed with LS-1 Proposal		$/Unit/Month	
Sodium Vapor					
9,000 Lumens (100W)	$11.56	$12.01	$12.01	$/Unit/Month	
14,000 Lumens (150W)	$13.56	$14.16	$14.16	$/Unit/Month	
27,000 Lumens (250 W)	$17.38	$18.13	$18.13	$/Unit/Month	
45,000 Lumens (400W)	$22.26	$22.26	$22.26	$/Unit/Month	
Part Night Credit					
Mercury Vapor					
7,000 Lumens (100W)	-$0.20	Removed with LS-1 Proposal		$/Unit/Month	
11,000 Lumens (150W)	-$0.28	Removed with LS-1 Proposal		$/Unit/Month	
20,000 Lumens (250W)	-$0.44	Removed with LS-1 Proposal		$/Unit/Month	
38,000 Lumens (400 W)	-$0.75	Removed with LS-1 Proposal		$/Unit/Month	
Sodium Vapor					
9,000 Lumens (100W)	-$0.11	Removed with LS-1 Proposal		$/Unit/Month	
14,000 Lumens (150W)	-$0.16	Removed with LS-1 Proposal		$/Unit/Month	
27,000 Lumens (150W)	-$0.31	Removed with LS-1 Proposal		$/Unit/Month	
45,000 Lumens (250 W)	-$0.48	Removed with LS-1 Proposal		$/Unit/Month	
Fuel Refund Credit - Applies to all kWh		($0.00148)	$0.00000	$/kWh	
Lg Cust Act 141 Capped 2005$		$0.00090	$0.00090	$/kWh	
Lg Cust Credits to comply w/Act 141		($0.00139)	($0.00139)	$/kWh	
Ms-31 Municipal Ornamental Lighting (Tariff Closed To New Customers)					
Energy Charge	$0.06482	$0.06676	$0.06676	$/kWh	
Fuel Refund Credit - Applies to all kWh		($0.00148)	$0.00000	$/kWh	
RC-S1 Residential Controlled Space Heating					
Customer Charge	$6.23	Tariff Cancelled		$/Month	
Energy Charge	$0.06630	Customers Moved to Rg-TOU			
CG-S1 Small C&I Controlled Space Heating					
Customer Charge	$6.23	Tariff Cancelled		$/Month	
Energy Charge	$0.06530	Customers Moved to Cg-TC		$/kWh	
Nature Wise					
NAT-R	$1.25	$2.40	$2.40	$/kWh	
NAT-C	$1.25	$2.40	$2.40	$/kWh	
ATS					
Automatic Transfer Switch					
Customer Charge					
Total Charge	$650.00	$667.00	$667.00	$/Month	
Maintenance Only	$210.00	$230.00	$230.00	$/Month	

*/ Rate Stabilization Mechanism Surcharge included in 2011 Rates and removed from 2012 Rates
**/ 2010 Fuel refund expires at end of 2011. No fuel refund identified for 2012.

SCHEDULE 2: AUTHORIZED RATES (Continued)

Rate Schedule Tariff Charge	Current Rates	Authorized 2011 Rates*	Authorized 2012 Rates		Daily Charge	
Pg-2A Parallel Generation						
Customer Charge	$8.00	$10.00	$10.00	$/Month	$0.3288	$/Day
On-Peak Energy Payment						
Delivery at Secondary Voltage	($0.09407)	($0.04153)	($0.04153)	$/kWh		
Delivery at Primary Voltage	($0.09623)	($0.04238)	($0.04238)	$/kWh		
Delivery at Transmission Voltage	($0.09504)	($0.04188)	($0.04188)	$/kWh		
Off-Peak Energy Payment						
Delivery at Secondary Voltage	($0.03722)	($0.02504)	($0.02504)	$/kWh		
Delivery at Primary Voltage	($0.03805)	($0.02556)	($0.02556)	$/kWh		
Delivery at Transmission Voltage	($0.03762)	($0.02525)	($0.02525)	$/kWh		
Interruptible Rates						
Secondary	($0.06233)	($0.06206)	($0.06206)	$/kWh		
Primary	($0.06068)	($0.06080)	($0.06080)	$/kWh		
Transmission	($0.05985)	($0.06006)	($0.06006)	$/kWh		
Pg-Solar Generation						
Customer Charge	$2.00	$2.00	$2.00	$/Month	$0.0658	$/Day
Energy Credit	($0.25)	($0.25)	($0.25)	$/kWh		
Pg-Biogas Generation						
Customer Charge						$/Day
Secondary	$30.50	$30.50	$30.50	$/Month	$1.0027	$/Day
Primary	$58.30	$58.30	$58.30	$/Month	$1.9167	$/Day
Energy Credits						
On-Peak (Secondary)	($0.10355)	($0.10355)	($0.10355)	$/kWh		
On-Peak (Primary	($0.10645)	($0.10645)	($0.10645)	$/kWh		
On-Peak (Transmission)	($0.10500)	($0.10500)	($0.10500)	$/kWh		
Off-Peak (Secondary)	($0.05917)	($0.05917)	($0.05917)	$/kWh		
Off-Peak (Primary	($0.06083)	($0.06083)	($0.06083)	$/kWh		
Off-Peak (Transmission)	($0.06000)	($0.06000)	($0.06000)	$/kWh		
Extension Allowances						
Residential - Year Round	$205	$360	$360	$/Extension		
Residential - Seasonal	$103	$180	$180	$/Extension		
C&I - 0-15 kW - Year Round	$205	$360	$360	$/Extension		
C&I - 0-15 kW - Seasonal	$103	$180	$180	$/Extension		
C&I - 16-50 kW - Year Round	$1,130	$1,065	$1,065	$/Extension		
C&I - 16-50 kW - Seasonal	$565	$533	$533	$/Extension		
C&I - 51 kW & Over - Year Round	$2,640	$2,280	$2,280	$/Extension		
C&I - 51 kW & Over - Seasonal	$1,320	$1,140	$1,140	$/Extension		
C&I - Demand and Energy - $/kW	$33	$27	$27	$/kW		

*/ Rate Stabilization Mechanism Surcharge included in 2011 Rates and removed from 2012 Rates
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Wisconsin Public Service Corporation

Present and Authorized Distribution Service Revenue by Customer Class

Distribution Classes and Other Cost Categori	Volumes	Margin Revenue at Current Rates	Margin Cost of Service COSS A	Margin Cost of Service COSS B	Margin Revenue at Authorized Rates	Change from Revenue at Current Rates	Percent Margin Change
Residential							
Residential (Rg-3)	214,123,761	$ 96,492,825			$ 90,304,661	$ (6,188,164)	(6.41)%
Residential - Seasonal (Rg-3)	1,072,474	$ 679,556			$ 648,561	$ (30,994)	(4.56)%
Subtotal	215,196,235	$ 97,172,381	$ 92,279,356	$ 63,704,611	$ 90,953,222	$ (6,219,158)	(6.40)%
Commercial & Industrial, Cg-ST (0 to 2,000)							
Firm Commercial (Cg-FST)	16,186,410	$ 7,093,374			$ 6,626,345	$ (467,029)	(6.58)%
Seasonal Commercial (Cg-FST)	27,914	$ 14,776			$ 13,969	$ (807)	(5.46)%
Subtotal Cg-ST	16,214,324	$ 7,108,150	$ 6,813,990	$ 5,063,799	$ 6,640,314	$ (467,836)	(6.58)%
Commercial & Industrial, Cg-S (2,001 to 20,000)							
Firm Commercial (Cg-FS)	68,845,042	$ 17,269,139			$ 15,949,269	$ (1,319,870)	(7.64)%
Seasonal Commercial (Cg-FS)	18,407	$ 5,004			$ 4,652	$ (352)	(7.03)%
Transport Commercial (Cg-TS)	250,365	$ 43,888			$ 39,254	$ (4,634)	(10.56)%
Transport-A Commercial (Cg-TSA)	363,458	$ 65,750			$ 59,462	$ (6,288)	(9.56)%
Interdepartmental (Cg-FS)	1,362,000	$ 285,599			$ 259,584	$ (26,014)	(9.11)%
Subtotal Cg-S	70,839,272	$ 17,669,379	$ 14,542,228	$ 16,268,164	$ 16,312,222	$ (1,357,157)	(7.68)%
Commercial & Industrial, Cg-M (20,001 to 200,000)							
Firm Commercial (Cg-FM)	52,351,128	$ 8,591,984			$ 8,695,524	$ 103,540	1.21%
Interruptible Commercial (Cg-IM)	2,893,286	$ 369,130			$ 346,551	$ (22,579)	(6.12)%
Transport Commercial (Cg-TM)	23,503,332	$ 2,376,405			$ 2,351,285	$ (25,120)	(1.06)%
Transport-A Commercial (Cg-TMA)	7,529,750	$ 874,022			$ 874,022	$ -	-
Season-Opp Commercial (Cg-SOS-M)	1,292,298	$ 175,789			$ 166,484	$ (9,305)	(5.29)%
Subtotal Cg-M	87,569,794	$ 12,387,329	$ 13,207,848	$ 17,987,921	$ 12,433,865	$ 46,536	0.38%
Commercial & Industrial, Cg-L (200,001 to 2,400,000)							
Firm Commercial (Cg-FL)	7,344,441	$ 711,252			$ 513,884	$ (197,368)	(27.75)%
Interruptible Commercial (Cg-IL)	6,645,086	$ 586,450			$ 495,097	$ (91,353)	(15.58)%
Transport Commercial (Cg-TL)	122,253,913	$ 7,161,774			$ 6,517,864	$ (643,910)	(8.99)%
Transport-A Commercial (Cg-TLA)	745,812	$ 51,749			$ 51,674	$ (75)	(0.14)%
Subtotal Cg-L	136,989,252	$ 8,511,224	$ 7,336,876	$ 17,084,507	$ 7,578,519	$ (932,705)	(10.96)%
Commercial & Industrial, Cg-SL (> 2,400,000)							
Subtotal Cg-SL	175,609,289	$ 6,231,767	$ 7,847,453	$ 20,618,617	$ 5,593,490	$ (638,277)	(10.24)%
Interruptible Electric Generation, Cg-IEG (200,000+)							
Interruptible Electric Generation (Cg-IEG)	853,000	$ 239,444			$ 227,469	$ (11,976)	(5.00)%
Power Department (Cg-IEG)	12,717,000	$ 2,337,015			$ 2,158,607	$ (178,407)	(7.63)%
Subtotal Cg-IEG	13,570,000	$ 2,576,459	$ 433,264	$ 1,434,281	$ 2,386,076	$ (190,383)	(7.39)%
Coal Displacement Gas Transportation (CDG	4,062,317	$ 184,163	$ 240,835	$ 539,951	$ 149,136	$ (35,027)	(19.02)%
Total Gas Rate Margin Revenue	720,050,483	$ 151,840,852	$ 142,701,850	$ 142,701,851	$ 142,046,846	$ (9,794,007)	(6.45)%
Authorized Rate Revenue Change		$ 142,470,852			$ 142,470,852	$ (9,370,000)	(6.17)%
Revenue Excess (Shortfall) at Proposed Rates		$ (9,370,000)			$ (424,007)	$ (424,007)	(0.28)%
Cost of Gas		$ 220,432,544			$ 220,432,544	$ -	-
Total Gas Rate Revenue		$ 372,273,396			$ 362,479,390	$ (9,794,007)	(2.63)%
Plus Other Revenue		$ 2,325,579			$ 2,325,579	$ -	-
Total Gas Revenue		$ 374,598,975			$ 364,804,969	$ (9,794,007)	(2.61)%

Wisconsin Public Service Corporation

Present and Authorized Gas Rates

	Present Rates	Authorized Rates
Residential		
Daily Customer Charge - (Rg-3)	$ 0.2301	$ 0.2301
Daily Customer Charge - Seasonal Service (Rg-3)	$ 0.4602	$ 0.4602
Daily Customer Charge - (Rg-T)	$ 0.3369	$ 0.3369
Daily Transportaion Administrative Charge (Rg-T)	$ 1.2329	$ 1.2329
Volumetric Charges:		
Distribution Service Charge - (Rg-3)	$ 0.3051	$ 0.2861
Distribution Service Charge - (Rg-T)	$ 0.2247	$ 0.2193
Daily Balancing Charge	$ 0.0009	$ 0.0009
Gas Acquisition Charge (Rg-3)	$ 0.0368	$ 0.0269
Standard Commercial (Cg-FST, Annual Usage < 2,000 therms)		
Daily Customer Charge	$ 0.2301	$ 0.2301
Daily Customer Charge - Seasonal	$ 0.4602	$ 0.4602
Volumetric Charges:		
Distribution Service Charge	$ 0.3051	$ 0.2861
Daily Balancing Charge	$ 0.0009	$ 0.0009
Gas Acquisition Charge	$ 0.0368	$ 0.0269
Small Commercial (Annual Usage 2,001 - 20,000 therms)		
Daily Customer Charge - (Cg-FS)	$ 0.6904	$ 0.6904
Daily Customer Charge - Seasonal (Cg-FS)	$ 1.3808	$ 1.3808
Daily Customer Charge - (Cg-TS, TSA)	$ 0.9863	$ 0.9863
Telemetering Charge (Cg-TS)	$ 0.9205	$ 0.8285
Transportation Administrative Charge (Cg-TS, CG-TSA)	$ 1.2329	$ 1.2329
Volumetric Charges:		
Distribution Service Charge - (Cg-FS)	$ 0.1657	$ 0.1587
Distribution Service Charge - (Cg-TS, TSA)	$ 0.1332	$ 0.1159
Daily Balancing Charge	$ 0.0009	$ 0.0009
Gas Acquisition Charge (Cg-FS)	$ 0.0368	$ 0.0247

Wisconsin Public Service Corporation

Present and Authorized Gas Rates

	Present Rates	Authorized Rates
Medium Commercial (Annual Usage 20,001 - 200,000 therms)		
Daily Customer Charge - (Cg-FM)	$ 3.1233	$ 3.1233
Daily Customer Charge - Seasonal (Cg-FM)	$ 6.2466	$ 6.2466
Daily Customer Charge - (Cg-IM, Cg-SOS-M, TM, TMA)	$ 4.4384	$ 4.4384
Telemetering Charge (Cg-IM, Cg-TM)	$ 0.9205	$ 0.8285
Transportation Administrative Charge (Cg-TM, Cg-TMA)	$ 1.2329	$ 1.2329
Volumetric Charges:		
Distribution Service Charge (FM)	$ 0.0984	$ 0.1129
Distribution Service Charge - (Cg-IM, Cg-SOS-M, TM, TMA)	$ 0.0782	$ 0.0782
Daily Balancing Charge	$ 0.0009	$ 0.0009
Gas Acquisition Charge (Gc-FM)	$ 0.0368	$ 0.0247
Gas Acquisition Charge (Gc-IM, Cg-SOS-M)	$ 0.0282	$ 0.0210
Large Commercial (200,001 to 2,400,000)		
Daily Customer Charge	$ 19.5616	$ 19.5616
Daily Customer Charge - Seasonal (Cg-FL)	$ 39.1233	$ 39.1233
Telemetering Charge (Cg-FL, Cg-IL, Cg-TL, Cg-SOS-L)	$ 0.9205	$ 0.8285
Transportation Administrative Charge (Cg-TL, Cg-TLA)	$ 1.2329	$ 1.2329
Demand Charge	$ 0.1475	$ 0.1475
Volumetric Charges:		
Distribution Service Charge	$ 0.0354	$ 0.0353
Daily Balancing Charge	$ 0.0009	$ 0.0009
Gas Acquisition Charge (Cg-FL)	$ 0.0288	$ 0.0180
Gas Acquisition Charge (Cg-IL, Cg-SOS-L)	$ 0.0226	$ 0.0162
S-Large Commercial (> 2,400,000)		
Daily Basic Distribution Charge	$ 127.6274	$ 127.6274
Telemetering Charge (Cg-ISL, Cg-TSL)	$ 0.9205	$ 0.8285
Transportation Administrative Charge (Cg-TSL, Cg-TSLA)	$ 1.2329	$ 1.2329
Demand Charge	$ 0.0833	$ 0.0833
Volumetric Charges:		
Distribution Service Charge	$ 0.0280	$ 0.0280
Daily Balancing Charge	$ 0.0009	$ 0.0009
Gas Acquisition Charge (Cg-ISL)	$ 0.0226	$ 0.0162

Wisconsin Public Service Corporation

Present and Authorized Gas Rates

	Present Rates	Authorized Rates
Interruptible Electric Generation (>200,000)		
Daily Basic Distribution Charge	$ 229.9726	$ 229.9726
Telemetering Charge	$ 0.9205	$ 0.8285
Demand Charge	$ 0.0649	$ 0.0649
Volumetric Charges:		
Distribution Service Charge	$ 0.0189	$ 0.0137
Daily Balancing Charge	$ 0.0009	$ 0.0009
Gas Acquisition Charge	$ 0.0226	$ 0.0138
Coal Displacement Gas Transportation		
Daily Basic Distribution Charge	$ 127.6274	$ 127.6274
Telemetering Charge	$ 0.9205	$ 0.8285
Transportation Administrative Charge (CDGT)	$ 1.2329	$ 1.2329
Demand Charge	$ 0.0616	$ 0.0700
Volumetric Charges:		
Distribution Service Charge (CDGT)	$ 0.0201	$ 0.0202
Daily Balancing Charge	$ 0.0009	$ 0.0009
Base Average Cost of Gas Rates:		
Commodity ("Comm") rate	$ 0.5904	$ 0.4500
Peak Day Demand ("D1") rate	$ 0.0975	$ 0.1314
Annual Demand ("D2") rate	$ 0.0100	$ 0.0168
Balancing ("Bal") rate	$ 0.0039	$ 0.0062

Wisconsin Public Service Corporation

Present and Authorized Gas Rates

	Present Rates	Authorized Rates
Act 141 Volumetric Distribution Rates 1/		
Residential (Rg-3)	$ 0.0092	$ 0.0107
Commercial & Industrial, Cg-ST (0 to 2,000)	$ 0.0065	$ 0.0109
Commercial & Industrial, Cg-S (2,001 to 20,000)	$ 0.0065	$ 0.0109
Commercial & Industrial, Cg-M (20,001 to 200,000)	$ 0.0065	$ 0.0109
Commercial & Industrial, Cg-L (200,001 to 2,400,000)	$ 0.0065	$ 0.0109
Commercial & Industrial, Cg-SL (> 2,400,000)	$ 0.0065	$ 0.0109
Interruptible Electric Generation, Cg-IEG (200,000+)	$ 0.0065	$ 0.0109
Coal Displacement Gas Transportation (CDGT)	$ 0.0065	$ 0.0109

1/ Act 141 volumetric distribution rates are included in the above volumetric Distribution Service Charges.

	Present Rates	Authorized Rates
Gas Revenue Stabilization Mechanism - 2011 Rate Adjustment 2/		
Residential (Rg-3)	$ -	$ 0.0183
Commercial & Industrial, Cg-FST (0 to 2,000)	$ -	$ 0.0183
Commercial & Industrial, Cg-FS (2,001 to 20,000)	$ -	$ 0.0234
Commercial & Industrial, Cg-FM (20,001 to 200,000)	$ -	$ 0.0234

2/ Gas Revenue Stabilization Mechanism Adjustments are included in the above volumetric distribution service charges and sunset on December 31, 2011.

Wisconsin Public Service Corporation

Monthly Residential Bill Comparison

Gas Costs	Summer	Winter
Firm Sales Service	0.4730	0.6044

Monthly Use Therms	Current Customer Charge	Current Distribut'n Charges	Total Monthly Cost	Gas Costs	Total Costs	Authorized Customer Charges	Authorized Distribut'n Charges	Total Monthly Cost	Gas Costs	Total Costs	Monthly Bill Increase (Decrease)	Monthly Percent Increase (Decrease)
Rg-1: Residential Firm Sales Service During Summer Months												
5	$ 7.00	$ 1.71	$ 8.71	$ 2.36	$ 11.08	$ 7.00	$ 1.57	$ 8.57	$ 2.36	$ 10.93	$ (0.14)	(1.30)%
15	$ 7.00	$ 5.14	$ 12.14	$ 7.09	$ 19.24	$ 7.00	$ 4.71	$ 11.71	$ 7.09	$ 18.80	$ (0.43)	(2.25)%
26 avg.	$ 7.00	$ 8.91	$ 15.91	$ 12.30	$ 28.21	$ 7.00	$ 8.16	$ 15.16	$ 12.30	$ 27.46	$ (0.75)	(2.66)%
35	$ 7.00	$ 12.00	$ 19.00	$ 16.55	$ 35.55	$ 7.00	$ 10.99	$ 17.99	$ 16.55	$ 34.54	$ (1.01)	(2.85)%
50	$ 7.00	$ 17.14	$ 24.14	$ 23.65	$ 47.79	$ 7.00	$ 15.70	$ 22.69	$ 23.65	$ 46.34	$ (1.45)	(3.02)%
75	$ 7.00	$ 25.71	$ 32.71	$ 35.47	$ 68.18	$ 7.00	$ 23.54	$ 30.54	$ 35.47	$ 66.02	$ (2.17)	(3.18)%
103	$ 7.00	$ 35.31	$ 42.31	$ 48.72	$ 91.03	$ 7.00	$ 32.33	$ 39.33	$ 48.72	$ 88.05	$ (2.98)	(3.27)%
125	$ 7.00	$ 42.85	$ 49.85	$ 59.12	$ 108.97	$ 7.00	$ 39.24	$ 46.24	$ 59.12	$ 105.36	$ (3.61)	(3.32)%
150	$ 7.00	$ 51.42	$ 58.42	$ 70.95	$ 129.37	$ 7.00	$ 47.09	$ 54.08	$ 70.95	$ 125.03	$ (4.34)	(3.35)%
200	$ 7.00	$ 68.56	$ 75.56	$ 94.60	$ 170.16	$ 7.00	$ 62.78	$ 69.78	$ 94.60	$ 164.38	$ (5.78)	(3.40)%
300	$ 7.00	$ 102.84	$ 109.84	$ 141.90	$ 251.74	$ 7.00	$ 94.17	$ 101.17	$ 141.90	$ 243.07	$ (8.67)	(3.44)%
Rg-1: Residential Firm Sales Service During Winter Months												
5	$ 7.00	$ 1.71	$ 8.71	$ 3.02	$ 11.74	$ 7.00	$ 1.57	$ 8.57	$ 3.02	$ 11.59	$ (0.14)	(1.23)%
15	$ 7.00	$ 5.14	$ 12.14	$ 9.07	$ 21.21	$ 7.00	$ 4.71	$ 11.71	$ 9.07	$ 20.77	$ (0.43)	(2.04)%
26	$ 7.00	$ 8.91	$ 15.91	$ 15.72	$ 31.63	$ 7.00	$ 8.16	$ 15.16	$ 15.72	$ 30.88	$ (0.75)	(2.38)%
35	$ 7.00	$ 12.00	$ 19.00	$ 21.16	$ 40.15	$ 7.00	$ 10.99	$ 17.99	$ 21.16	$ 39.14	$ (1.01)	(2.52)%
50	$ 7.00	$ 17.14	$ 24.14	$ 30.22	$ 54.36	$ 7.00	$ 15.70	$ 22.69	$ 30.22	$ 52.92	$ (1.45)	(2.66)%
75	$ 7.00	$ 25.71	$ 32.71	$ 45.33	$ 78.04	$ 7.00	$ 23.54	$ 30.54	$ 45.33	$ 75.87	$ (2.17)	(2.78)%
103	$ 7.00	$ 35.31	$ 42.31	$ 62.26	$ 104.56	$ 7.00	$ 32.33	$ 39.33	$ 62.26	$ 101.59	$ (2.98)	(2.85)%
125 avg	$ 7.00	$ 42.85	$ 49.85	$ 75.55	$ 125.40	$ 7.00	$ 39.24	$ 46.24	$ 75.55	$ 121.79	$ (3.61)	(2.88)%
150	$ 7.00	$ 51.42	$ 58.42	$ 90.67	$ 149.08	$ 7.00	$ 47.09	$ 54.08	$ 90.67	$ 144.75	$ (4.33)	(2.91)%
200	$ 7.00	$ 68.56	$ 75.56	$ 120.89	$ 196.45	$ 7.00	$ 62.78	$ 69.78	$ 120.89	$ 190.67	$ (5.78)	(2.94)%
300	$ 7.00	$ 102.84	$ 109.84	$ 181.33	$ 291.17	$ 7.00	$ 94.17	$ 101.17	$ 181.33	$ 282.50	$ (8.67)	(2.98)%
Avg. Annual Residential Billing												
774	$ 83.99	$ 265.33	$ 349.31	$ 447.33	$ 796.64	$ 83.99	$ 242.96	$ 326.95	$ 447.33	$ 774.27	$ (22.37)	(2.81)%

Wisconsin Public Service Corporation
Monitored Fuel Costs For 2011
WPSC Historical Methodology for NYMEX

Month	Fuel Costs	kWh	$ / kWh	Cumulative $ / kWh
January	$25,752,250	1,241,656,780	$0.02074	$0.02074
February	$25,426,250	1,153,487,877	$0.02204	$0.02137
March	$31,427,250	1,202,074,084	$0.02614	$0.02296
April	$23,806,250	1,120,739,002	$0.02124	$0.02255
May	$25,651,250	1,179,958,266	$0.02174	$0.02239
June	$27,388,250	1,244,087,466	$0.02201	$0.02233
July	$31,856,250	1,373,209,528	$0.02320	$0.02247
August	$30,846,250	1,325,520,388	$0.02327	$0.02257
September	$27,928,250	1,227,665,407	$0.02275	$0.02259
October	$27,543,250	1,233,363,080	$0.02233	$0.02257
November	$26,945,250	1,179,906,752	$0.02284	$0.02259
December	$29,529,250	1,273,258,190	$0.02319	$0.02264
Total	$334,100,000	14,754,926,820	$0.02264	$0.02264

Docket 6690-UR-120

Deferral Amortization Schedule

Deferral:	PSCW Deferral Authorization	Notes	Amortization Period	Test Year Amount Electric	Test Year Amount Gas
DePere Energy Center Premium	6690-EB-104	4	2011-2023	$ 2,280,420	$0
Rail Car Recoveries	6690-UR-118	4	2011-2012	70,520	0
Emission Allowances	6690-UR-119	4	2011-2012	(509,368)	0
KNPP NQDT	05-EI-136	1	2011-2012	(22,449)	0
KNPP - Loss on Sale (Contingent)	05-EI-136 6690-UR-117	1	2011-2012	2,364,204	0
Weston 3 Lightning - Purchased Power	5-GF-120 6690-UR-119	1	2011-2014	2,800,000	0
Weston 3 Lightning - Purchased Power	5-GF-120 6690-UR-119	5	2011-2014	825,058	0
WUMS Socialization of MISO Congestion & Loss Costs & Credits	05-GF-165	4	2011-2012	246,492	0
DMD and R&E Tax Credits	6690-GF-115	4	2011-2012	268,987	0
Tax Deferrals	Precedent	3	2011-2012	26,448	7,356
Conservation Escrow (pre-Act 141)	various	3	2011-2012	5,413,354	1,727,057
Conservation Escrow (Act 141)	various	1	2011-2012	12,550,412	5,736,716
Additional FOE payments	6690-UR-119	1	2011-2012	11,735,383	7,276,790
2009 RSM Adjustment	6690-UR-119	1	2011	14,436,532	7,099,722
Crane Creek Production Tax Credits	6690-UR-119	3	2011-2012	654,958	0
Manufactured Gas Plant Cleanup	6690-UR-110	2	2011-2012	0	(15,000)
Act 141 Deferred Costs from 2009	6690-UR-119	1	2011-2012	(117,492)	(319,975)
High Country Wind Generation Pre-construction	6690-GF-122 6690-UR-120	4	2011-2012	231,500	0
Totals				**$ 53,254,959**	**$ 21,512,666**

(1) Amount applies to Wisconsin Retail customers only.
(2) Amount allocated between Wisconsin and Michigan Retail customers.
(3) Amount allocated between all WPSC jurisdictions. (WI, MI, FERC)
(4) Amount allocated between Wisconsin Retail and FERC Market Based customers.
(5) Amount applies to FERC Market Based Rate customers only.